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FUEL QUALITY/PROCESSING STUDY

VOLUME III– FUEL UPGRADING STUDIES

Chemicals and Minerals Division
Gulf Research & Development Company

October 1981

Prepared for
NATIONAL AERONAUTICS AND SPACE ADMINISTRATION
Lewis Research Center
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for
U.S.DEPARTMENT OF ENERGY
Energy Technology
Fossil Fuel Utilization Division

FUELS QUALITY/PROCESSING STUDY

GULF RESEARCH & DEVELOPMENT COMPANY - FINAL REPORT

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National Aeronautics and Space Administration
Lewis Research Center
21000 Brookpark Road
Cleveland, Ohio 44135

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U. S. Department of Energy
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16. Abstract

The final report consists of four volumes. Volume I, Overview and Results, presents the conclusions the study obtained from its evaluation of the feasible paths from liquid fossil fuel sources to generated electricity. The segments from which these paths were built are the results from the fuel upgrading schemes, on-site treatments, and exhaust gas treatments detailed in the subsequent volumes. This volume, Volume III, Fuel Upgrading Studies, describes the methods used to calculate the refinery selling prices for the turbine fuels of low quality. Also included in Volume III is detailed descriptions and economics of the upgrading schemes. These descriptions include flow diagrams showing the interconnection between processes and the stream flows involved. Each scheme is in fact a complete, integrated, stand-alone facility. Except for the purchase of electricity and water, each scheme provides its own fuel and manufactures, when appropriate, its own hydrogen.

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IV - NEW REFINERIES TO UPGRADE FUEL

I. INTRODUCTION

This volume describes the upgrading schemes from which upgrading cost and energy requirements were derived. Each scheme is a self-sufficient and produces a marketable slate of products.

A few schemes are base cases. These produce conventional fuel products for which selling price estimates were already available. The other schemes reflect a variety of ways for making certain lower-than-conventional-quality fuels. These fuels are deemed potentially usable in industrial gas turbines. As detailed in the body of this volume, comparisons between these other schemes and the base case schemes provide the costs for producing industrial gas turbine fuels from the several raw materials.

This volume is organized into two parts. One part treats schemes based upon modification of "generic" existing refineries. The other treats schemes representing grass roots upgrading facilities.

Raw materials for the modified existing refinery schemes include petroleum and shale oil. Coal liquids processing in modified existing refineries does not appear to make economic sense. The grass root schemes process not only petroleum components and shale oil but also coal liquids.

This volume is the third of four volumes constituting the study's final report. The first summarizes the results. The second presents a literature survey. The last volume examines the economics of relevant on site options for treating the turbine fuel or processing the turbine exhaust gases.

II. NON LINEAR REFINERY MODEL

We have used one of our proprietary models to develop costs for producing low quality turbine fuels. This model is routinely used for preliminary, non-site specific cost estimates for new or altered processes. It is also used to assess impacts of processing changes on fuel product values. The model has the capability to represent a wide variety of refinery configurations.

The proprietary nature of the model derives from three sources. These are: first, the "process correlations", second, the "investment/ capacity correlations" and third, the "optimization methods".

The "process correlations" represent separate processing units within a refinery. These correlations consist of mathematical relationships whereby information about feed rates, feed qualities and processing conditions generates information about product rates, product qualities and utility stream demands. Each correlation is itself a mathematical model previously developed by the contractor. Although the processes are frequently not proprietary, the experimental data used to develop a correlation are proprietary. Also proprietary are the decisions as to which modeling methods would be used for a particular correlation as well as the decisions as to which variables constitute key parameters in a correlation.

The "investment/capacity correlations" estimate aggregate investment costs associated with a process from the capacity of that process. Much of the data upon which these correlations are based is proprietary. Furthermore, the decisions as to which data to use, which relationships to use,

and which capacity term to use for a particular process are all proprietary.

The contractor does not place in the public domain either the model or the method whereby the non-linear equations representing the model are solved. The mathematical approach is reasonably well known and the contractors version of this approach has been described in several published articles. A bibliography is included herewith.

The processing steps and blending facilities available in the model are those typically found in large integrated refineries. The model has the capability to process five crude oils simultaneously, and it includes a crude oil assay program to calculate yields and product properties for crude tower fractions using data from a crude assay. Crudes can be replaced by other liquid fuel inputs. Data on prices, costs, product specifications, unit investments and utility consumptions, and process unit yields and operating conditions are built into the model but can be easily overidden by the user. Investments, yields and stream qualities are represented by equations and correlations, many of which are non-linear. Products are produced and blended to meet specified quality and quantity restrictions.

The model calculates complete material and utility balances, manufacturing expenses, and required investments. The model can optimize a refining scheme on the basis of maximizing either profit or return on investment. Optimization may include selecting feedstocks to process units, blending products, determining operating conditions or satisfying constraints on the flow or property specifications of the products. Possible products are one to three grades of gasoline, one to four grades of residual fuels, jet fuel, No. 2 fuel, C_3 and C_4 LPG, naphtha, ehtylene, propylene, butadiene feedstock, sulfur, coke and refinery fuel.

In all of the cases studied, operating conditions for some units and product stream disposition were automatically selected to meet specified constraints. The model contains a large number of processing alternatives so that many different configurations could be specified and simulated.

Evaluation of new processes, raw materials or products was made by case study to determine the economic consequences of adding, removing or replacing a process or raw material or product set up to stimulate an existing or "typical" refinery, the profit for this refining operation serving as the base case. When a change is made, the economics of the changed scheme can be compared to those of the base case and the impact of the change thereby established.

The model calculates a material balance and the resulting stream properties for the proposed refining scheme unit by unit. In some instances, the model has the capability of changing process operating conditions, such as reformer severity, in order to optimize results or satisfy the product constraints. Up to 25 streams may be included in gasoline blending depending on which process units are included in the refinery scheme. Blending of the various streams satisfies the specifications for the finished gasoline. Specifications include gasoline vapor pressure, maximum lead and minimum octanes. In addition, ASTM distillation, density, maximum and minimum quantities of each grade of gasoline and the fraction of the total gasoline in each grade may be specified. A total of six residual and middle distillate fuel products can be produced from approximately 22 different streams in the refinery. These fuel products can be blended to meet specifications on quantity, sulfur content and viscosity.

After a complete material balance on the refinery scheme has been calculated, the utility consumptions and investment for each unit are calculated. A complete utility, fuel and hydrogen balance is also made. If additional hydrogen is required over that available from reforming and pyrolysis, a hydrogen plant will be automatically provided; if not the excess is used as fuel. Finally, total investment, return from products, manufacturing expense, profit and return on investment are usually calculated.

In this study final economics calculations were done external to the model. Here we were usually using the model as a basis for calculating a feed or product value rather than determining profitability based on known stream prices.

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III - EXISTING REFINERIES TO UPGRADE FUEL

III.1 Summary

Costs have been calculated for upgrading in existing refineries, in the 1985 time frame, low-sulfur petroleum residual; high-sulfur, high-metals petroleum residual; shale oil from surface retorting of shale; and shale oil from modified in situ (MIS) retorting of shale to gas turbine fuels of varying quality. Two upgrading strategies have been evaluated: (a) extensive alteration of the boiling range of the upgraded fuel to minimize upgrading requirements or to make available by-product credits to offset upgrading costs; and (b) direct removal of contaminants with minimum change in boiling range to obtain high yields of gas turbine fuel. Upgrading of syncrudes from liquefaction of coal in a typical existing refinery in which this syncrude replaces the normal crude charge was found to be economically infeasible.

III. 1.1 Summary of Cases Evaluated

The following charge stocks and processing schemes have been evaluated in this task. These schemes assess the adaptation of existing refineries to the production of gas turbine fuels:

Charge Stock	Processing Scheme	Case Number(s)
Low-Sulfur Residual (Vacuum Bottoms) from South Louisiana Crude Oil	Solvent Decarbonizing	1.10
	Delayed Coking plus Hydrotreating of: Full-Range (C_5-950°F); Naphtha-Free (375-950°F); or Furnace Oil-Free (650-950°F) Coker Distillate	1.21, 1.22, 1.23
	Hydrodesulfurization at Moderate, Intermediate, or High Severity	1.31, 1.32, 1.33
High-Sulfur, High Metals Residual (Vacuum Bottoms) from Ceuta (Venezuelan) Crude Oil	Solvent Decarbonizing plus Hydrotreating of Decarbonized Oil	2.10
	Delayed Coking plus Hydrotreating of Full-Range (C_5-950°F); Naphtha-Free (375-950°F); or Furnace Oil-Free (650-950°F) Coker Distillate	2.21, 2.22, 2.23
	Hydrodesulfurization at Moderate, Intermediate, or High Severity	2.31, 2.32, 2.33

Surface-Retorted Paraho Shale Oil	Hydrotreating at High Severity with or without Second-Stage Hydrotreating of Disillate from Primary Hydrotreating	3.10, 3.20
	Delayed Coking plus Hydro-treating of Coker Distillate	3.30
Modified In Situ-Retorted Shale Oil	Hydrotreating at High Severity with or without Second-Stage Hydrotreating of Distillate from Primary Hydrotreating	4.10, 4.20

Solvent decarbonizing or delayed coking of petroleum residueal explore significant reduction of boiling range to facilitate contaminants removal. Hydro-desulfurization and hydrotreating explore direct removal of contaminants with very little reduction of boiling range. Each of the aforementioned upgrading units would be installed as new facilities in the existing refinery.

Base case schemes charging South Louisiana or Ceuta crude oils, respectively, have also been evaluated for producing gasoline and distillate products excluding gas turbine fuel in cases 1.00, 2.00, and 3.00. Net revenues calculated from generated cases are applied to cases 1.10 to 2.33. These net revenues plus 30% return before taxes on new capital dedicated to gas turbine fuel upgrading along with forecast prices of by-products are used to calculate prices of gas turbine fuels.

Net revenue from a base case scheme charging South Louisiana crude oil, case 3.00, is used to calculate raw shale oil prices. The crude oil is replaced with raw surface-retorted or modified in-situ retorted shale oil for production of conventional products excluding gas turbine fuel (cases 3.01 and 4.01). Net revenue from the base case scheme, case 3.00, plus 30% return before taxes on new capital for processing shale oil in cases 3.01 or 4.01 permits the pricing of raw shale oil. This calculated price of raw shale oil is then used in evaluating schemes for production of gas turbine fuel, cases 3.10 to 4.20. Pricing of gas turbine fuel in these schemes includes also the net revenue generated in the base case, case 3.00, in addition to 30% return before taxes on new capital for gas turbine fuel upgrading facilities.

The economic evaluations for these cases are presented in Tables III-1 to III-4, and schematic flow diagrams for each case are shown in Figures III-I to III-20. Sufficient detail is presented in these tables so that forecast crude oil or product prices or cost factors can be revised if necessary, and gas turbine fuel prices recalculated. It should be emphasized that by-product values can off-set to a large extent the manufacturing expense for gas turbine fuel upgrading and thus have a significant effect on the calculated gas turbine fuel price.

South Louisiana crude oil has been selected as the low-sulfur crude oil in the study since it is produced in large volumes and has been for many years the sole crude supply to a large refinery. The capacity and processing configuration of this refinery are specified in the base case for this study, Case 1.00. This crude oil represents a typical low-sulfur, low-metals crude oil, from which gas turbine fuel should be capable of being produced at relatively low costs.

Ceuta crude oil, or residual therefrom, is processed or marketed in this country largely for residual fuel oil product. It contains high concentrations of sulfur and metals which should result in a maximum range of gas turbine fuel upgrading costs.

III.1.2 Results

Gas turbine fuels containing essentially no trace metals (less than 1 ppm vanadium) can be produced from low-sulfur petroleum residual by any of the three processes evaluated at costs less than the price differential between No. 2 fuel oil and low-sulfur No. 6 fuel. The price of gas turbine fuel is thus lower than that for No. 2 fuel oil. The most economical route for upgrading this residual includes coking plus hydrotreating of 650-950°F coker gas oil. Credits from upgrading coker naphtha and furnace oil to gasoline and No. 2 fuel oil products more than offset costs for upgrading residual to gas turbine fuel.

Gas turbine fuels containing as low as 11 ppm vanadium can be produced from the high-sulfur, high-metals residual selected by decarbonizing or hydrodesulfurization at costs less than the price differential between No. 2 fuel oil and high-sulfur No. 6 fuel oil. These two processes are economically equivalent in this application. An essentially metals-free gas turbine fuel can be produced from this residual by coking plus hydrotreating, but at significantly higher costs. The price of gas turbine fuel exceeds the No. 2 fuel oil price, thus rendering this scheme economically unattractive.

Essentially metals-free gas turbine fuels containing low nitrogen and sulfur can be produced economically from raw shale oil in the scheme including hydrotreating followed by catalytic cracking. The price of gas turbine fuel could be lower than that for No. 2 fuel oil if second-stage hydrotreating to ensure thermal stability is not required. The scheme including coking of raw shale oil followed by hydrotreating of coker distillate is not economically viable in the context of an existing refinery since the opportunity for use of, and revenue obtainable from, the existing catalytic cracking and alkylation units are no longer available.

III.2 Introduction

The efficiency of generation of electricity from gaseous or liquid fuels is greatly increased by co-generation in which a stationary gas turbine is the primary converter and exhaust gas is used to generate steam for secondary conversion. However, the future availability of these fuels is a major concern. Natural gas and petroleum distillates, now widely used in this service, likely will not be available in sufficient quantities or will be directed to higher priority use in the transportation or home-heating sectors to fulfill potential stationary gas turbine fuel demands toward the end of this century.

Petroleum residuals are currently used to some extent as fuel for stationary gas turbines. However, these fuels are limited by the current turbine design and operations requiring low concentrations of trace metals, particularly vanadium, and of nitrogen and sulfur compounds. These requirements will conflict with the increasing concentrations of these contaminants in residual fuels resulting from the projected increases in the proportion of heavy, high-sulfur crudes in the refiner's crude slate. Also, the viscosity of residual fuels fired is limited to that for No. 6 fuel oil. This excludes direct combustion of high-viscosity vacuum bottoms, the refinery stream of lowest value and the ideal candidate for gas turbine fuel upgrading with regard to availability.

This study has been carried out to assess the costs incurred with upgrading of petroleum residuals and raw shale oil to gas turbine fuels of varying quality in existing petroleum refineries.

III.3 Technical Approach

Costs have been calculated for upgrading residual fuel oils from low- and high-sulfur petroleum crude oils, shale oil from surface retorting of a Western shale, and shale oil from modified in situ (MIS) retorting of a Western shale, respectively, in representative existing refineries to produce gas turbine fuels having varying properties and contaminant levels. Upgrading of syncrude from liquefaction of coal has not been evaluated in detail and is not included in this report. A brief analysis indicates that after initial hydrotreating in new facilities to remove contaminants, the product contains only about 7% boiling above 550°F and there is very little incentive for further conversion in the existing refinery. The loss in revenue from shutting down major refinery conversion units would result in prohibitively high costs for gas turbine fuels. This upgrading scheme will be evaluated in detail in Task IV in the context of new grass-roots plants.

The primary quality criteria considered in the upgraded fuel oil product include vanadium, sulfur and nitrogen concentrations, respectively, and viscosity. The extent of upgrading for a given processing scheme was varied when possible to develop an upgrading cost versus product quality relationship. Minimum target contaminant levels of 0.5 ppm vanadium, 0.7% sulfur and 0.3% nitrogen were considered. The maximum viscosity considered was 1130 cs at 100°F (200 SFS at 122°F) for a residual type fuel.

The representative existing petroleum refineries selected were those designed for high production of gasoline. Major process units include fluid catalytic cracking (FCC) of gas oil, alkylation of propylene and butylenes, catalytic reforming of naphtha, and treating of distillates to produce No. 2 fuel oil. Vacuum bottoms is not converted to light products but is blended with light furnace oil to No. 6 fuel oil product.

Yields and properties of products from upgrading in each processing step, except for severe hydrotreating of shale oil from surface retorting, or hydrotreating of distillate from coking of the shale oil, were provided by Gulf Research & Development Company, based on estimates from pilot plant

operations or from available process correlations. Process data for severe hydrotreating of surface retorted shale oil, or coker distillate therefrom, were taken from a report[1] prepared by Chevron Research Company for the U.S. Department of Energy.

Two strategies have been evaluated for upgrading petroleum residual (vacuum bottoms) from either low-sulfur or high-sulfur crude oils:

III.3.1 Extensive Reduction in Boiling Range

1. One processing scheme includes delayed coking of vacuum bottoms followed by hydrotreating of coker distillate to saturate olefins. Most of the trace metals (vanadium plus nickel), sulfur, and nitrogen in the feedstock are rejected to coke by-product. To develop a cost versus gas turbine fuel boiling range relationship, the boiling ranges of the coker distillate charge to hydrotreating include: (a) total, C_5-950°F, distillate; (b) naphtha-free, 375-950°F, distillate; and (c) naphtha plus furnace oil-free, 650-950°F, gas oil, respectively. In the latter two cases, the coker naphtha, C_5-375°F, or naphtha plus furnace oil, C_5-650°F, are processed within the existing refinery to produce gasoline and No. 2 fuel oil which can be credited against the cost for upgrading residual to gas turbine fuel.

2. A second processing scheme includes solvent (propane plus butane) decarbonizing of vacuum bottoms with rejection of asphalt containing high-boiling asphaltenes and high concentrations of metals, sulfur and nitrogen to fuel oil by-products.

III.3.2 Direct Removal of Metals, Sulfur and Nitrogen by Hydrodesulfurization

Upgrading of vacuum bottoms by direct hydrodesulfurization employing a commercially proven process has been evaluated at each of three severity levels. The desulfurized naphtha-free product, 375°F$^+$, is blended with light furnace oil to meet the maximum viscosity specification for No. 6 fuel oil of

about 1130 cs at 100°F. Naphtha produced from desulfurization is upgraded within the refinery to produce gasoline for credit against gas turbine fuel upgrading cost.

As desulfurization severity level is increased, concentrations of metals (nickel plus vanadium) and nitrogen, as well as sulfur, in the gas turbine fuel product decrease. Simultaneously, the viscosity of the desulfurized product decreases, which results in a lower light furnace oil requirement to meet viscosity specification. Thus, with operation at higher severity levels, additional furnace oil is released for production of No. 2 fuel oil which is available for credit against gas turbine fuel upgrading cost.

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III.4 Description of Upgrading Schemes

III.4.1 Upgrading of Residual from Low-Sulfur Crude Oil

South Louisiana crude oil, which contains 0.31 wt% sulfur and is produced and refined in large volumes, was selected as the low-sulfur crude oil in this study. This crude is the primary crude supply to a large domestic refinery which serves as the basis for the existing refinery in this study. A primary departure, however, is that vacuum bottoms is blended with light furnace oil to No. 6 fuel oil product instead of being charged to delayed coking for conversion to light products as in actual operation. A crude charge rate of 200,000 B/CD, the approximate current throughput of this refinery, was specified. A schematic flow diagram for this Base Case refinery (Case 1.00) is presented in Figure III-1 in Appendix A.

As shown in Figure III-1, the primary processing units in the Base Case include the FCC, alkylation, and naphtha reforming units to produce gasoline at high yield, 56% on crude, or 111,169 B/CD. The naphtha reforming unit is operated at a severity to produce debutanized reformate having 90.0 Research octane number, clear. This results in a gasoline pool having an $\frac{R+M}{2}$ (Research octane number plus Motor octane number divided by 2) octane rating of 89.3 with a maximum allowable TEL concentration of 0.5 gm lead per gallon. The pool octane number is obtained from the following octane numbers and distribution of the several grades of gasoline projected for 1985:

Grade	Leaded Regular	Unleaded Regular	Unleaded Premium	Pool
$\frac{R+M}{2}$	89.0	88.0	91.5	89.3
Vol%	25	45	30	100

Jet fuel and No. 2 fuel oil are produced at rates of 20,000 B/CD and 57,876 B/CD, respectively. Benzene is produced at a rate of 3,170 B/CD by extraction from light reformate and dealkylation of toluene which is extracted also from light reformate. Hydrogen sulfide produced from the FCC and

desulfurization units is converted to product sulfur. Propane recovered from the gas plant and alkylation unit is marketed as LPG product. Butanes produced from the several processing units are supplemented with purchased iso and normal butanes to meet alkylation unit and gasoline vapor pessure requirements, respectively.

The vacuum bottoms, 1100°F+, feedstock for gas turbine fuel, comprising 6.5 vol% of this crude, contains 8.4 ppm vanadium, 1.04 wt% sulfur and 0.15 wt% nitrogen. About one-half of this bottoms stream in the Base Case is blended with light furnace oil, 375-510°F, and FCC decanted oil to produce low-sulfur, 1.0% sulfur, No. 6 fuel oil at a rate of 13,842 B/CD. This fuel oil, containing 4.2 ppm vanadium and 0.08 wt% nitrogen, could be considered as a gas turbine fuel of marginal quality as limited by the high vanadium content. The remainder of the vacuum bottoms plus a small quantity of decanted oil supplement off-gas produced from the several refining units to supply fuel requirements for the scheme.

III.4.1.1 Production of Gas Turbine Fuel by Decarbonizing Low-Sulfur Vacuum Bottoms

A schematic flow diagram for production of gas turbine fuel by decarbonizing of vacuum bottoms from South Louisiana crude (Case 1.10), is shown in Figure III-2. Vacuum bottoms plus 12% FCC decanted oil used as wash oil are decarbonized in a new unit to produce an essentially demetallized oil containing 0.2 ppm vanadium at a yield of 55.0 vol% on vacuum bottoms. This oil is blended with a small quantity of light furnace oil to produce gas turbine fuel having maximum No. 6 fuel oil viscosity specification at a rate of 7,881 B/CD.

Most of the asphalt (91%) from decarbonizing is burned hot as refinery fuel to supplement off-gas from the several refining units. The remainder of the asphalt is blended with decanted oil and light furnace oil to low-sulfur, 1.0% sulfur, No. 6 fuel oil product. Production rates of gasoline, jet fuel, benzene, propane LPG, and sulfur are identical with those in the Base Case. Production of No. 2 fuel oil is slightly less than in the Base Case.

III.4.1.2 Production of Gas Turbine Fuel by Delayed Coking of Low-Sulfur Vacuum Bottoms plus Hydrotreating of Coker Distillate

A schematic flow diagram for production of gas turbine fuel by delayed coking of vacuum bottoms from South Louisiana crude plus hydrotreating of total, C_5-950°F, coker distillate (Case 1.21) is shown in Figure III-3. Most of the vacuum bottoms, 96%, at a rate of 12,430 B/CD, is charged to a new delayed coking unit to produce a metals-free coker distillate, C_5-950°F, at a yield of 74.6% or 9,267 B/CD. Coker distillate is hydrotreated in a new unit employing a commercially-proven process and catalyst to produce 9,469 B/CD of gas turbine fuel. This product contains very low concentrations of sulfur and nitrogen, 0.05 wt% and 0.09 wt%, respectively, and has a distillate viscosity of about 1.0 cs at 100°F. Hydrogen consumed in hydrotreating is supplied from by-product hydrogen from the catalytic reforming unit in the existing refinery.

The remainder of the vacuum bottoms plus FCC decanted oil and THD polymer is burned as refinery fuel to supplement refinery off-gas. Gasoline production is slightly higher than from the Base Case as a result of the additional alkylate produced from coker propylene and butylenes. Production of No. 2 fuel oil is significantly higher than in the Base Case as a result of releasing furnace oil requirements from blending to No. [illegible] fuel oil product. Production of propane LPG and sulfur are also significa[illegible] igher than from the Base Case. Low-sulfur (1.4% sulfur) coke is pr[illegible] a rate of 658 short tons/CD. New facilities are installed to scrub hydrogen sulfide from refinery off-gas and to convert the hydrogen sulfide to product sulfur to supplement the units in the existing refinery.

A scheme in which the naphtha-free, 375-650°F, coker distillate is hydrotreated for gas turbine fuel production (Case 1.22) is shown in Figure III-4. Gas turbine fuel has slightly higher concentrations of sulfur and nitrogen, a higher viscosity and is produced at a lower rate, 6,962 B/CD, than that from the previous scheme in which total coker distillate is hydrotreated. Light coker gasoline, C_5-150°F, is Merox sweetened and blended into

the refinery gasoline pool. Coker naphtha, 150-375°F, is pretreated and reformed in admixture with straight-run naphtha in the existing refinery units. Gasoline production, 113,582 B/CD, is thus increased significantly above that from the Base Case.

A scheme in which naphtha and furnace oil-free, 650-950°F, coker distillate is hydrotreated for gas turbine fuel production (Case 1.23) is shown in Figure III-5. Production of gas turbine fuel is reduced to 3,433 B/CD. The sulfur and nitrogen concentrations and viscosity are significantly higher than those for gas turbine fuel produced by hydrotreating total coker distillate. Coker naphtha, C_5-375°F, is upgraded in the existing refinery as described for Case 1.22. Coker furnace oil, 375-650°F, is charged to the FCC unit in the existing refinery in admixture with straight-run gas oil. Gasoline production from this scheme is increased to 117,062 B/CD compared with 111,169 B/CD in the Base Case. Production of No. 2 fuel oil is also signficantly higher than for the Base Case, 59,644 B/CD versus 57,876 B/CD.

III.4.1.3 Production of Gas Turbine Fuel by Hydrodesulfurization of Low-Sulfur Vacuum Bottoms

Schemes including hydrodesulfurization of vacuum bottoms from South Louisiana crude have been evaluated at moderate, intermediate and high severity in Cases 1.31, 1.32, and 1.33, respectively. Schematic flow diagrams are presented in Figures III-6, III-7 and III-8, respectively. In Case 1.31, the bulk, 93%, of the vacuum bottoms, 12,157 B/CD, is charged to the hydrodesulfurization unit with the remainder consumed along with FCC decanted oil and THD polymer as refinery fuel. The desulfurized 375°F$^+$ residuum is blended with light furance oil to produce 17,103 B/CD of residual type gas turbine fuel containing 1.3 ppm vanadium, 0.25 wt% sulfur, and 0.09 wt% nitrogen. The light gasoline fraction, C_5-170°F, from desulfurization is blended into the refinery gasoline pool. Naphtha, 170-375°F, from desulfurization is pretreated and reformed in units in the existing refinery to produce additional

high octane number gasoline. Production of No. 2 fuel oil, 54,993 B/CD, is significantly lower than in the Base Case, 57,876 B/CD, because of a greater light furnace oil requirement to meet maximum viscosity specification of gas turbine fuel.

Ammonium bisulfide formed from ammonia and hydrogen sulfide produced in the hydrodesulfurization reactions is scrubbed from reactor effluent with water. Sour water is charged to a stripping tower to recover ammonia, 2.1 short tons/CD, and hydrogen sulfide which, along with that recovered from the desulfurization units, is converted to product sulfur, 44 long tons/CD, in a conventional Claus unit equipped with tail gas desulfurization facilities.

As hydrodesulfurization severity is increased to intermediate and high levels, the vanadium concentration in the gas turbine fuel decreases to 0.6 ppm and 0.1 ppm, respectively. Sulfur content of the gas turbine fuel product decreases from 0.25 wt% at moderate severity to 0.17 wt% at high severity. However, nitrogen content remains unchanged at 0.09%. Also, as severity is increased, the viscosity of the desulfurized 375°F$^+$ residuum decreases, which results in lower furnace oil requirements to meet maximum turbine fuel viscosity specification, and a corresponding increase in No. 2 fuel oil production. Gasoline production increases only slightly with increase in desulfurization severity.

III.4.2 Upgrading of Residual from High-Sulfur Crude Oil

Ceuta (Venezuelan) crude oil containing 1.32 wt% sulfur and 133 ppm vanadium, and considered representative of the source of the high-sulfur, high-metals residual fuel oil marketed in this country, was selected as the high-sulfur crude oil in this study. Costs for upgrading this very high-metals residual to gas turbine fuel should define the upper cost limits for upgrading residuals to gas turbine fuel. A hypothetical existing refinery has been assumed charging this crude at a rate of 100,000 B/CD. A schematic flow diagram for the Base Case refinery (Case 2.00) is presented in Figure III-9.

As shown in Figure III-9, the primary processing units in the Base Case include the FCC, alkylation and naphtha reforming units to produce gasoline at a yield of 48.8% or 48,823 B/CD. No. 2 fuel oil is produced at a rate of 22,087 B/CD by desulfurization of the bulk of the heavy straight-run furnace oil and blending the resulting product with untreated light and heavy straight-run furnace oils to a maximum product sulfur specification of 0.2%. Benzene and jet fuel are not produced.

Vacuum bottoms, 1000°F+, comprising 21.5 vol% of this crude, contains 540 ppm of vanadium, 3.05 wt% sulfur, and 0.65 wt% nitrogen. Ninety percent of the vacuum bottoms is blended with FCC light gas oil and decanted oil plus light straight-run furnace oil to produce 29,217 B/CD of No. 6 fuel oil containing 367 ppm vanadium, 2.66 wt% sulfur, and 0.44 wt% nitrogen. The remainder of the vacuum bottoms is consumed hot to supplement gas produced from the refinery units as refinery fuel.

III.4.2.1 Production of Gas Turbine Fuel by Decarbonizing of High-Sulfur Vacuum Bottoms

A schematic flow diagram for production of gas turbine fuel by decarbonizing of vacuum bottoms from Ceuta crude (Case 2.10) is presented in Figure III-10. Vacuum bottoms is decarbonized in a new unit to recover 75% of an oil containing 86 ppm vanadium, 2.62 wt% sulfur, and 0.39 wt% nitrogen. This oil is then desulfurized in a new unit to a product containing 13.3 ppm vanadium, 0.27 wt% sulfur, and 0.31 wt% nitrogen. Gas turbine fuel containing 11.6 ppm vanadium, 0.26% sulfur, and 0.27% nitrogen is produced at a rate of 19,392 B/CD by blending the desulfurized oil with light furnace oil to the maximum viscosity specification for No. 6 fuel oil.

About one-half of the asphalt from decarbonizing, containing high concentrations of metals, sulfur, and nitrogen, is blended with light furnace oil to a sulfur content of 3.0% and to reduced viscosity for use, along with refinery off-gas, as refinery fuel. The remainder of the asphalt is blended with FCC decanted oil and light furnace oil to No. 6 fuel oil having 3.0 wt% sulfur and maximum specification viscosity.

Gasoline and propane LPG production rates are the same and No. 2 fuel oil production rate is slightly greater than in the Base Case refinery. Production of sulfur is almost three-fold that from the Base Case.

III.4.2.2 Production of Gas-Turbine Fuel by Delayed Coking of High-Sulfur Vacuum Bottoms plus Hydrotreating of Coker Distillate

A schematic flow diagram for production of gas turbine fuel by delayed coking of vacuum bottoms from Ceuta crude plus hydrotreating of total, C_5-950°F, coker distillate (Case 2.21) is shown in Figure III-11. Ninety-nine percent of the vacuum bottoms is charged to a new delayed coking unit to produce an essentially metals-free coker distillate, C_5-950°F, at a yield of 70.9% or 15,060 B/CD. Coker distillate is hydrotreated in a new unit to produce 15,263 B/CD of gas turbine fuel containing 0.16 wt% sulfur and 0.09 wt% nitrogen, and having a viscosity of about 1.0 cs at 100°F. The remainder of the vacuum bottoms is blended with FCC decanted oil which, along with refinery off-gas, is consumed as refinery fuel.

Gasoline production in this scheme is slightly higher than in the Base Case as a result of the additional alkylate produced from coker propylene and butylenes. Production of propane LPG is also increased from recovery from coker gas. Production of No. 2 fuel oil is increased significantly over that from the Base Case as a result of releasing furnace oil from blending to No. 6 fuel oil which is no longer produced. A small new desulfurization unit, 3,740 B/SD charge capacity, is installed to supplement the existing unit to meet increased furnace oil desulfurization requirement. Sulfur production is increased almost three-fold as in the scheme with decarbonizing of vacuum bottoms. High-sulfur, 4.1% sulfur, coke is produced at a rate of 1,232 short tons/CD.

A scheme in which the naphtha-free, 375-950°F, coker distillate, is hydrotreated to gas turbine fuel (Case 2.22) is shown in Figure III-12. Production of gas turbine fuel is reduced from 15,263 B/CD in the previous

scheme to 11,261 B/CD. Contaminants in this fuel are at a somewhat higher level, 0.20 wt% sulfur and 0.11 wt% nitrogen. Gasoline production is increased substantially over that from the Base Case, 53,505 B/CD versus 48,823 B/CD, from upgrading of coker naphtha in addition to increased alkylate production. Production of No. 2 fuel oil, 29,399 B/CD, is the same as in the previous scheme with hydrotreating of total coker distillate. Small new naphtha pretreating and reforming units and a small new furnace oil desulfurization unit are installed to supplement the capacities of the existing units.

A scheme in which naphtha and furnace oil free, 650-950°F, coker gas oil is hydrotreated to gas turbine fuel (Case 2.23) is shown in Figure III-13. The total production of vacuum bottoms is charged to coking. Production of gas turbine fuel is reduced to 5,418 B/CD, the sulfur and nitrogen concentrations of which are increased slightly to 0.25 wt% and 0.19 wt%, respectively. Coker furnace oil is catalycically cracked in admixture with straight-run gas oil in the existing FCC unit. Gasoline production is increased to 58,700 B/CD and No. 2 fuel oil production to 30,146 B/CD. Small new naphtha pretreating, naphtha reforming, and furnace oil desulfurization units are installed to supplement the capacities of the existing units as in the previous case (Case 2.22). Also, the existing FCC and alkylation units are revamped to meet increased capacity requirements of 21% and 28%, respectively. About 75% of FCC decanted oil is consumed as refinery fuel to supplement refinery off-gas, with the remainder marketed as high-sulfur No. 6 fuel oil product.

III.4.2.3 Production of Gas Turbine Fuel by Hydrodesulfurization of High-Sulfur Vacuum Bottoms

Schemes have been evaluated for hydrodesulfurization of vacuum bottoms from Ceuta crude at moderate, intermediate, and high severity (Cases 2.31, 2.32, and 2.33) and are shown in Figures III-14, III-15 and III-16, respectively. In the moderate severity scheme, about 95% of the vacuum bottoms is desulfurized by about 88% to produce a naphtha-free, $375°F^+$,

residuum containing 59 ppm vanadium, 0.40% sulfur, and 0.42% nitrogen at 104 volume % yield. Desulfurized residuum is then blended with light furnace oil to produce 25,325 B/CD of gas turbine fuel having the maximum viscosity specification for No. 6 fuel oil and containing 50.4 ppm vanadium, 0.37 wt% sulfur, and 0.36 wt% nitrogen. Light gasoline, C_5-150°F, from desulfurization is blended into the gasoline pool. Naphtha, 150-375°F, is pretreated and reformed in the existing refinery units to produce additional high octane number gasoline.

Gasoline production is increased slightly over that from the Base Case refinery from the additional naphtha produced from desulfurization. No. 2 fuel oil production is increased substantially as a result of reduced furnace oil blending requirements for gas turbine fuel. A small new furnace oil desulfurization unit, 3,620 B/SD charge capacity, is installed to supplement the existing unit. A small hydrogen manufacturing unit, 4,420 x 10^3 SCF/SD, reforming refinery off-gas, is installed to supplement by-product hydrogen from the existing naphtha reforming unit for gasoline production. The remainder of the vacuum bottoms plus FCC decanted oil are consumed as refinery fuel to supplement refinery off-gas.

In Cases 2.32 and 2.33, desulfurization of vacuum bottoms is increased to 91% and 94%, respectively. Production of gas turbine fuel decreases by small extents. Gas turbine fuel vanadium concentration is reduced to 31.0 and 10.9 ppm; and sulfur concentration to 0.29% and 0.20%, respectively. Gas turbine fuel nitrogen concentration at intermediate desulfurization severity is the same as at moderate severity, 0.36%, but is reduced to 0.30% at high severity. Production of gasoline and No. 2 fuel increase slightly as desulfurization severity is increased. New hydrogen manufacturing plant capacity increases, but new furnace oil desulfurization capacity remains unchanged as severity level is increased.

III.4.3 Production of Gas Turbine Fuel by Upgrading of Surface Retorted Shale Oil

A Base Case refinery (Case 3.00) was selected which is similar to an existing refinery located in the Midwest charging low-sulfur crude oil for primary production of gasoline and No. 2 fuel oil as operated by a major oil company. South Louisiana crude oil is charged at a rate of 50,000 B/CD in a scheme shown in Figure III-17.

Straight-run gas oil, 628-1100°F, is charged to the FCC unit at a rate of 20,564 B/CD. Butylenes plus about 60% of the propylene produced in the FCC unit are recovered for production of alkylate at a rate of 5,171 B/CD. FCC light gas oil is hydrotreated and blended with caustic treated straight-run furnace oil for production of 15,634 B/CD of No. 2 fuel oil. A portion of light straight-run furnace oil is hydrotreated for production of 2,100 B/CD of jet fuel.

About 88% of the 1100°F$^+$ vacuum bottoms is blended with FCC decanted oil and straight-run light furnace oil to produce 5,224 B/CD of low-sulfur No. 6 fuel oil. The remainder of the vacuum bottoms along with refinery off-gas is consumed as refinery fuel.

Light straight-run naphtha, 155-375°F, is pretreated and reformed to produce a debutanized reformate having 91.0 Research octane number clear. A gasoline pool having 89.3 $\frac{R+M}{2}$ octane rating with 0.5 gm lead/gal is produced at a rate of 29,034 B/CD.

III.4.3.1 Severe Hydrotreating of Raw Shale Oil followed by Fluid Catalytic Cracking of Residuum

A scheme for upgrading surface retorted shale oil to gas turbine fuel in the existing petroleum refinery based on initial severe hydrotreating of raw shale oil (Case 3.10) is shown in Figure III-18. Raw shale oil from retorting by the Paraho process and which is upgraded at the retort site to enable transportation by pipeline is charged to the refinery at the rate of 50,000 B/CD. This raw shale oil containing a low concentration of vanadium,

0.2 ppm, but high concentrations of sulfur, 0.66 wt%, nitrogen, 2.18 wt%, and oxygen, 1.16 wt%, replaces the normal crude oil charge to the refinery.

Shale fines are removed in a new four-stage electrostatic unit similar to a crude oil desalting unit. De-ashed shale oil is then charged to a new hydrotreating unit operating at severe conditions of about 2,000 psig reactor pressure, 700°F temperature, and 0.6 V/H/V space velocity over a commercial catalyst, as employed in pilot plant runs[1] conducted by Chevron Research Company to achieve over 95% removal of nitrogen, sulfur, and oxygen compounds. Arsenic compounds in raw shale oil are quantitatively removed, as claimed by Chevron, in a guard chamber in the reactor to avoid poisoning of the hydrotreating catalyst. Hydrogen is consumed at a high rate of 1,900 SCF/B. The existing crude oil atmospheric distillation tower serves as a fractionator for hydrotreater products. The crude oil vacuum flash tower is shut down.

Atmospheric bottoms, 640°F$^+$, from the hydrotreating unit has a sufficiently low nitrogen content, 0.19%, to enable charge to the existing FCC unit for high conversion (84.8 vol%) to gasoline and lighter products. A high yield of gasoline, 63.5 vol% of C_5-430°F, is obtained from this feedstock. Total FCC butylenes and 40% of the propylene produced are alkylated in the existing HF alkylation unit.

The 375-640°F hydrotreated distillate fraction, after diverting a small quantity to refinery fuel, is hydrotreated in a new second-stage unit to assure production of a thermally stable gas turbine fuel in regards to gum-forming tendency. A new second-stage unit is provided since the required capacity greatly exceeds that of the existing furnace oil desulfurization unit. Gas turbine fuel containing essentially no vanadium, 0.002 wt% sulfur, and 0.02 wt% nitrogen, and having a viscosity of 2.4 cs at 100°F is produced at a rate of 21,869 B/CD in lieu of No. 2 fuel oil product.

The C_6-375°F naphtha fraction from hydrotreating is pretreated in a new unit to produce acceptable reforming unit feedstock. The design operating conditions of the existing naphtha pretreater would probably not be adequate

to pretreat this feedstock because of the higher than normal nitrogen content, 70 ppm. Pretreated naphtha is reformed in the existing reforming unit using conventional catalyst to produce debutanized reformate having 95.0 Research octane number, clear. Total gasoline production having a pool $\frac{R+M}{2}$ octane rating of 89.3 in this scheme is 28,543 B/CD. Yields and properties of products from all processing units in this scheme, except the shale oil hydrotreating unit, were provided by Gulf Research and Development Company based on pilot plant operations.

Ammonium bisulfide formed from ammonia and hydrogen sulfide produced in the hydrotreating reactions is scrubbed from reactor effluent with water. Sour water is processed in a new Chevron waste water treating plant to recover ammonia, 208 short tons/CD, and hydrogen sulfide. Also, hydrogen sulfide is scrubbed from hydrotreator off-gas in a new conventional amine unit. Hydrogen sulfide is converted to product sulfur, 47 long tons/CD, in a new conventional unit equipped with tail gas desulfurization facilities.

Off-gas from the several refining units is charged to two new hydrogen manufacturing plants having a capacity of 61.9×10^6 SCF/SD each to supplement by-product hydrogen from the naphtha reforming unit to meet hydrogen requirements for the scheme. Propane is recovered at a rate of 872 B/CD from off-gas production.

A scheme has also been evaluated (Case 3.20) in which distillate from primary hydrotreating is marketed as a gas turbine fuel product without hydrotreating in a second stage. Although the sulfur and nitrogen contents of this product are only slightly higher than in the product from the previous scheme including second-stage hydrotreating, gum-forming tendency may exist which then would require further, possibly chemical, treatment prior to combustion.

III.4.3.2 Delayed Coking of Raw Shale Oil plus Hydrotreating of Coker Distillate

An alternative scheme in which surface retorted shale oil is upgraded by delayed coking followed by hydrotreating of coker distillate (Case 3.30) is shown in Figure III-19. Coking as the first processing step has the advantage of removing any solids suspended in the raw oil, most of the nonfilterable iron, and about 80% of the arsenic prior to catalytic processing. The coker distillate is more easily hydrotreated than raw shale oil, and the hydrogen consumption is much lower for a product of a given nitrogen content. Disadvantages for coking include the production of a low-quality, low-value coke at the expense of higher-value liquid products.

Raw shale oil, which replaces the normal crude charge to the refinery, is de-ashed and charged to a new delayed coking unit at a rate of 50,000 B/CD. Total coker distillate, C_5-950°F, essentially metals free, and containing 0.63 wt% sulfur and 1.75 wt% nitrogen, is produced at yield of 80.8 vol% or 40,416 B/CD based on Chevron pilot plant data.[1] Coker distillate is hydrotreated at relatively moderate conditions, 1,700 psig reactor pressure and 1.2 V/H/V space velocity, to produce a 350-650°F distillate containing 0.008% sulfur and 0.30% nitrogen at a yield of 71.4 vol% or 28,868 B/CD. Yields and properties of products from hydrotreating were estimated based on Chevron pilot plant data[1] obtained at a higher severity level. The existing crude atmospheric distillation tower serves as a fractionator for hydrotreater products. The crude vacuum flash tower is shut down.

About 37% of the 650°F$^+$ bottoms from hydrotreating is consumed as refinery fuel to supplement refinery off-gas. The remainder of the bottoms is blended with 375-650°F middle distillate from hydrotreating to gas turbine product at a rate of 32,273 B/CD. Further hydrotreating of this distillate in a second-stage unit is not provided, since Chevron pilot plant results[1] indicate that it may be possible to produce a stable diesel fuel from primary hydrotreating only of coker distillate. Since hydrotreating of coker distillate results in almost complete conversion to gas turbine fuel and lighter products, the existing FCC and alkylation units are not required and are shut down.

Coker naphtha, 150-375°F, is pretreated in a new unit and reformed in the existing reforming unit to produce a debutanized reformate having 93.9 Research octane number, clear. Reformate is blended with coker light gasoline, C_5-150°F, and butanes to produce 6,714 B/CD of gasoline having an $\frac{R+M}{2}$ octane rating of 89.8 with a maximum TEL concentration of 0.5 gm lead per gallon. This rating is higher than the minimum specification of 89.3 for pool gasoline in 1985 in order to meet the minimum Research octane number specification of 94.0. Gasoline is produced in this scheme at a markedly lower rate than that, 28,543 B/CD, in the scheme including hydrotreating of whole raw shale oil because of the absence of FCC gasoline and alkylate components.

Hydrogen consumed in hydrotreating of coker distillate is 1,100 SCF/B, considerably lower than required for hydrotreating of whole raw shale oil, 1,900 SCF/B. A new hydrogen manufacturing plant employing steam reforming of a portion of the off-gas from the several refining units is provided at a capacity of 53.6 x 10^6 SCF/SD to supplement by-product hydrogen from the existing naphtha reforming unit.

III.4.4 Production of Gas Turbine Fuel by Upgrading of Modified In Situ Retorted Shale Oil

III.4.4.1 Severe Hydrotreating of Raw Shale Oil followed by Fluid Catalytic Cracking of Residuum

A scheme for upgrading modified in situ (MIS) retorted shale oil in an existing petroleum refinery based on an initial severe hydrotreating step (Case 4.10) is very similar to the scheme charging surface retorted shale oil (Case 3.10) and is shown in Figure III-20. MIS shale oil contains significantly less high-boiling fractions, has a lower density, and contains significantly less nitrogen than Paraho surface retorted shale oil, 1.4% versus 2.18%. Concentrations of sulfur and oxygen, 0.5% and 1.0%, respectively, are also less than in Paraho shale oil, 0.66% and 1.16%, respectively.

Hydrogen consumed in hydrotreating MIS shale oil to produce a residuum, 675°F$^+$, containing 0.19% nitrogen for acceptable FCC feedstock is significantly lower, 1,100 SCF/B, than for the surface retorted shale oil, 1,900 SCF/B. To produce the same yield of residuum to meet the capacity of the existing FCC unit, the product distillation cut point is increased to 675°F compared with 640°F for surface retorted shale. The yield of middle distillate, 375-675°F, from hydrotreating MIS shale oil is higher than the yield of the 375-640°F middle distillate from hydrotreating surface retorted shale oil, 52.2 versus 47.5 vol%. However, the yield of naphtha, C_5-375°F, from hydrotreating MIS shale oil is lower, 12.1 versus 18.1 vol%. This results in a higher production of gas turbine fuel, 26,127 B/CD versus 21,869 B/CD, and a lower production of by-product gasoline, 25,807 B/CD versus 28,543 B/CD, for upgrading MIS shale oil compared with surface retorted shale oil.

In Case 4.10, the 375-675°F middle distillate from hydrotreating MIS shale oil is hydrotreated in a second-stage unit to ensure the production of a thermally stable gas turbine fuel. A scheme has also been evaluated (Case 4.20) in which the second-stage hydrotreating unit is not included.

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III.5 Gas Turbine Fuel Upgrading Costs

Gas turbine fuel upgrading costs were calculated for a U.S. Gulf Coast location in 1985. Prices for major petroleum products and electric power are those forecast by Data Resources, Inc. (DRI). Crude oil prices were based on the DRI price forecast for imported crude. The price for propane LPG was based on a relationship with No. 2 fuel oil price and prices for iso and normal butanes on relationships with gasoline price. The price for ammonia was based on the DRI price forecast for natural gas. The price for low-sulfur coke was based on a projected price for charge stock for electrode manufacture for the aluminum industry. The price for high-sulfur coke was based on its fuel value. Prices for sulfur and benzene were escalated from current Gulf Coast prices.

The investment for new facilities for upgrading including process units, catalysts and royalties, storage tanks, utility units and miscellaneous off-sites plus 20% contingency were estimated for 1984, the mid-point of a projected two-year construction period to enable start-up in 1985. Bases for the investment and operating cost estimates are presented in Table III-A in Appendix B. Labor and investment overhead factors for petroleum residual upgrading plants are those employed by a major oil company for a large refinery on the Gulf Coast. Corresponding factors for shale oil upgrading plants are those employed by this oil company at a smaller Midwest refinery.

III.5.1 Costs for Upgrading of Residual from Low-Sulfur Crude Oil

The economics for upgrading vacuum bottoms from low-sulfur, South Louisiana, crude oil for each of the seven schemes evaluated are presented in Table III-1 in Appendix B. The net revenue, total revenue less total expense, calculated for the Base Case refinery (Case 1.00) in which vacuum bottoms is blended to low-sulfur No. 6 fuel oil is \$728,743 x 10^3/year, exclusive of labor and investment burdens. This net revenue plus a profit of 30% before tax on incremental investment are stipulated to be provided in each case for

upgrading vacuum bottoms to gas turbine fuel. Production of gas turbine fuel, total plant investment for upgrading facilities, and the calculated price of gas turbine fuel for each case are as follows:

Upgrading of South Louisiana Vacuum Bottoms to Gas Turbine Fuel

Case	Description	Incremental Investment, $\$10^6$ (1984)	Gas Turbine Fuel B/CD	Gas Turbine Fuel Price, $/B (1985)
1.10	Decarbonizing	41	7,881	65.58
1.21	Coking + Hydrotreating of C_5-950°F Distillate	76	9,469	65.95
1.22	Coking + Hydrotreating of 375-950°F Distillate	72	6,962	62.21
1.23	Coking + Hydrotreating of 650-950°F Gas Oil	67	3,433	46.43
1.31	Moderate Severity Hydrodesulfurization	60	17,103	60.72
1.32	Intermediate Severity Hydrodesulfurizaiton	62	16,830	60.67
1.33	High Severity Hydrodesulfurization	64	16,714	60.71

The prices calculated above for gas turbine fuel compare with 1985 forecast prices for low-sulfur No. 6 fuel oil and No. 2 fuel oil of \$56.03/B and \$68.65/B, respectively. Differentials in prices calculated for gas turbine fuel over the forecast price for low-sulfur No. 6 fuel vary from -\$9.60/B in the scheme including coking of vacuum bottoms followed by hydrotreating of 650-950°F coker gas oil to \$9.92/B in the scheme including coking of vacuum bottoms followed by hydrotreating of total, C_5-950°F, coker distillate. These price differentials constitute upgrading costs which are considerably less than the \$12.62/B differential in price of No. 2 fuel oil over low-sulfur No. 6 fuel oil.

Costs for upgrading low-sulfur vacuum bottoms to gas turbine fuel have also been plotted as functions of vanadium, sulfur, and nitrogen contents of this fuel in Figures III-21, III-22, and III-23, respectively, in Appendix C. The primary objective in upgrading is reduction of trace metals (vanadium) content, along with viscosity to the maximum specification for No. 6 fuel oil or lower. Sulfur content is also simultaneously reduced extensively in each scheme, except for that including decarbonizing. However, no reduction in nitrogen content is achieved in any of these schemes. In the case of delayed coking plus hydrotreating of 650-950°F coker distillate, the nitrogen content is actually increased over that in vacuum bottoms by concentration in the coker heavy gas oil fraction.

As shown in the coking schemes, by-product credits obtained by upgrading naphtha or furnace oil by-products in the existing refinery have a very dramatic effect upon gas turbine fuel upgrading costs. The most favorable scheme economically includes coking of vacuum bottoms followed by hydrotreating of naphtha and furnace oil-free, 650-950°F, coker gas oil (Case 1.23). The greatly increased gasoline production in this scheme from upgrading coker naphtha and from cracking of coker furnace oil, 375-650°F, more than offsets the upgrading cost for gas turbine fuel, with the price of this product calculated to be less than for No. 6 fuel oil, \$46.43 versus \$56.03/B. However it should be noted that the production rate of gas turbine fuel in this scheme is relatively low, 3,433 B/CD, and its price, which is

calculated as the difference between large values, is sensitive to the forecast prices of the several by-products and the the assumptions employed in estimating investment and manufacturing expense.

If the naphtha-free, 375-650°F, coker distillate is hydrotreated to gas turbine fuel, with coker naphtha only upgraded in the existing facilities (Case 1.22), the price of gas turbine fuel, \$62.21/B, is increased greatly over that from the scheme in which both coker naphtha and furnace oil are upgraded. However, the price of gas turbine fuel in this case is still significantly lower than when total coker distillate is upgraded to gas turbine fuel and no significant by-product credits are obtained, \$65.95/B.

Direct hydrodesulfurization of vacuum bottoms is the second most favorable scheme of those evaluated for upgrading low-sulfur residual to gas turbine fuel. The calculated price of gas turbine fuel in this scheme, about \$60.70/B, is essentially independent of hydrodesulfurization severity. The greater investment and operating cost for higher severity operation is offset by increased No. 2 fuel oil by-product credit obtained as a result of the reduced viscosity of the desulfurized product and the reduced furnace oil requirement for blending to maximum viscosity specification. Thus, a gas turbine fuel of higher quality with lower impurity concentrations can be produced with no increase in price by increasing the desulfurization severity level.

The price of gas turbine fuel produced by decarbonizing of vacuum bottoms, \$65.58/B, is approximately equal to that obtained in the scheme including coking plus hydrotreating of total coker distillate, \$65.95/B. The higher investment and operating cost in the coking scheme is offset by a 20% increase in gas turbine fuel production. However, the gas turbine fuel produced in the coking scheme is of higher quality, i.e., lower impurities concentrations with a viscosity in the distillate range, compared with that from decarbonizing, with a viscosity in the residual fuel oil range.

III. 5.2 Costs for Upgrading Residual from High-Sulfur Crude Oil

The economics for upgrading vacuum bottoms from high-sulfur, Ceuta crude to gas turbine fuel for each of the seven schemes evaluated are presented in Table III-2. The net revenue calculated for the Base Case refinery in which vacuum bottoms is blended to high-sulfur No. 6 fuel oil is $260,473 x 10^3/year, exclusive of labor and investment burdens. This net revenue plus a profit of 30% before tax on incremental investment are stipulated to be provided in each case for upgrading vacuum bottoms to gas turbine fuel. Production of gas turbine fuel, total plant investment for upgrading facilities, and the calculated price of gas turbine fuel for each case are as follows.

Upgrading of Ceuta (Venezuelan) Vacuum Bottoms to Gas Turbine Fuel

Case	Description	Incremental Investment, $\$10^6$ (1984)	Gas Turbine Fuel B/CD	Gas Turbine Fuel Price, $/B (1985)
2.10	Decarbonizing	126	19,392	63.68
2.21	Coking + Hydrotreating of C_5-950°F Distillate	123	15,263	69.79
2.22	Coking + Hydrotreating of 375-950°F Distillate	142	11,261	70.45
2.23	Coking + Hydrotreating of 650-950°F Gas Oil	152	5,418	69.85
2.31	Moderate Severity Hydrodesulfurization	245	25,325	62.76
2.32	Intermediate Severity Hydrodesulfurization	255	25,096	63.31
2.33	High Severity Hydrodesulfurization	271	24,730	64.16

The prices calculated above for gas turbine fuel compare with 1985 forecast prices for high-sulfur No. 6 fuel oil and No. 2 fuel oil of $53.00/B and $68.65/B, respectively. Upgrading costs, which are the differentials in

prices calculated for gas turbine fuel over the price forecast for high-sulfur No. 6 fuel oil, vary from \$9.76/B in the scheme including moderate severity hydrodesulfurization to \$17.45/B in the scheme including coking plus hydrotreating of 375-950°F coker distillate.

Costs for upgrading high-sulfur vacuum bottoms to gas turbine fuel are plotted as functions of vanadium, sulfur, and nitrogen contents of this fuel in Figures III-24, III-25, and III-26, respectively in Appendix C. Decarbonizing and hydrodesulfurization are equivalent economically in upgrading high-sulfur vacuum bottoms to gas turbine fuel to a given vanadium, sulfur, or nitrogen concentration. Hydrodesulfurization requires about double the upgrading investment required for decarbonizing, but this is offset by a 30% increase in gas turbine fuel production rate. The cost of upgrading by hydrodesulfurization increases only slightly over a wide range of vanadium removal. However, it is not feasible with present-day desulfurization or decarbonizing technology to reduce the vanadium concentration of gas turbine fuel from this high-metals residual below about 11 ppm.

The schemes, including coking of high-sulfur, high-metals vacuum bottoms plus hydrotreating of coker distillate are capable of producing gas turbine fuel containing essentially no trace metals However, the upgrading costs are significantly greater than the price differential between No. 2 fuel oil and high-sulfur No. 6 fuel oil. The upgrading cost is essentially independent of the boiling range of gas turbine fuel product, which is contrary to that shown for upgrading low-sulfur residual. Higher by-product credits from upgrading coker naphtha or furnace oil are offset by high costs for new downstream refining units and for revamping of existing units. Therefore, production of low-metals content gas turbine fuel from high-sulfur, high-metals residual by this processing route is not economically justified.

III.5.3 Costs for Upgrading Surface Retorted Shale Oil

III.5.3.1 Severe Hydrotreating of Raw Shale Oil followed by Fluid Catalytic Cracking of Residuum

The economics for upgrading surface retorted shale oil to gas turbine fuel for each of two cases evaluated based on hydrotreating of raw shale oil followed by FCC of residuum are presented in Table III-3. The net revenue generated in the Base Case refinery charging South Louisiana crude oil (Case 3.00) is calculated to be \$181,021 x 10^3/year, exclusive of labor and investment burdens. This net revenue plus 30% profit on incremental investment was employed to calculate a price for raw shale oil for upgrading to conventional petroleum products, primarily gasoline and No. 2 fuel oil, for which price forecasts in 1985 have been obtained (Case 3.01). The price of raw shale is calculated on this basis to be \$50.86/B and compares with a price forecast for South Louisiana crude of \$62.00/B.

Using the price of raw shale oil as calculated above, the price of gas turbine fuel from the scheme including severe hydrotreating of raw shale oil plus second-stage hydrotreating of the distillate product (Case 3.10) is calculated to be \$68.63/B. This price is only slightly less than that for No. 2 fuel oil, \$68.65/B, and reflects the elimination of additives for No. 2 fuel oil. Otherwise, the quality and properties of gas turbine fuel are identical with those for No. 2 fuel oil.

If second-stage hydrotreating of distillate is eliminated in the above scheme on the assumption that it will not be required for production of stable gas turbine fuel, or that gum-forming tendency can be passivated by chemical additives (Case 3.20), the investment and operating costs for upgrading are significantly reduced, with price of gas turbine fuel reduced to \$65.93/B, \$2.72/B less than the price of No. 2 fuel oil.

III.5.3.2. Delayed Coking of Raw Shale Oil plus Hydrotreating of Coker Distillate

The shale oil upgrading scheme with coking as the initial processing step (Case 3.30) requires a total plant investment, as shown also in Table III-3, of only 75% of that for the scheme with severe hydrotreating as the initial processing step (Case 3.20). Fuel, power, chemicals, and catalyst consumptions are also greatly reduced. This results from the much milder operating conditions required in hydrotreating coker distillate to a given nitrogen content along with greatly reduced hydrogen consumption, compared with hydrotreating whole raw shale oil. Also, hydrotreating in the coking scheme is intentionally designed for lower severity operation to produce a gas turbine fuel having a higher nitrogen content of 0.3%, since there is no need to meet the lower nitrogen requirement for FCC feedstock. However, the reduction in operating costs is much more than offset by the large loss in by-product gasoline resulting from shutting down of the existing FCC and alkylation units. Also, not withstanding that these units are shut down in this scheme, the net revenue generated in the Base Case in which these units are in operation is stipulated to be provided in the gas turbine fuel upgrading scheme. The result is that the price of gas turbine fuel obtained by upgrading shale oil by coking plus hydrotreating escalates to $85.58/B, which is $16.93/B greater than the price of No. 2 fuel oil. Thus, upgrading of raw shale oil by coking plus hydrotreating in an existing refinery in which raw shale oil replaces the normal crude charge is not economically feasible.

III.5.4 Costs for Upgrading MIS Shale Oil

Economics for upgrading MIS shale oil in an existing refinery based on initial severe hydrotreating to meet FCC feedstock requirements (Cases 4.10 and 4.20) are presented in Table III-4. To provide the same net revenue generated in the Base Case refinery charging South Louisiana crude oil, $181,021 x 10^3/year, the required price for raw MIS shale oil to produce conventional petroleum products is calculated to be $53.81/B. The higher price for MIS shale oil compared with the calculated price of surface retorted

shale oil, \$50.86/B, results largely from the much lower hydrogen consumption in hydrotreating MIS shale oil and the attendant lower investment and operating costs.

Based on the calculated price of raw MIS shale oil, the price calculated for gas turbine fuel including initial high severity hydrotreating to produce FCC feedstock followed by second-stage hydrotreating of distillate is \$58.63/B, the same as in the scheme for surface retorted shale oil. As pointed out previously, this price is only slightly lower than that of No. 2 fuel oil because of the elimination of additives for the latter fuel. If second-stage hydrotreating of distillate is not provided (Case 4.20) the price of gas turbine fuel is reduced to \$66.04/B, which is similar to the price of \$65.93/B calculated for the corresponding scheme upgrading surface retorted shale oil.

III.6 Conclusions

Petroleum residuals or raw shale oil can be upgraded economically in representative existing petroleum refineries to produce high-quality gas turbine fuels. A low-sulfur petroleum residual can be upgraded to gas turbine fuel containing less than 1 ppm vanadium by decarbonizing, by delayed coking plus hydrotreating of coker distillate, or by hydrodesulfurization. Upgrading cost, the calculated price of gas turbine fuel less the forecast price of low-sulfur No. 6 fuel oil, for 1985 ranges from -$9.60/B to $9.92/B of gas turbine fuel product. These costs are lower than the differential between prices for No. 2 fuel oil and low-sulfur No. 6 fuel oil products.

A negative value for upgrading cost, in which the calculated price for gas turbine fuel is less than the price for No. 6 fuel oil, is obtained for the scheme including coking of vacuum bottoms followed by hydrotreating of 650-950°F coker gas oil to gas turbine fuel. By-product credits from the additional gasoline produced by reforming of coker naphtha and catalytic cracking of coker furnace oil in existing refinery units more than offset costs for upgrading.

Hydrodesulfurization of low-sulfur vacuum bottoms is more favorable economically than decarbonizing, coking plus hydrotreating of total coker distillate, C_5-950°F, or coking plus hydrotreating of naphtha-free coker distillate, 375-950°F. This results from the higher production rate of gas turbine fuel by hydrodesulfurization with no degradation of liquid to coke or asphalt.

A high-sulfur, high-metals petroleum residual can be upgraded economically to a gas turbine fuel containing as low as 11 ppm vanadium, about 0.25 wt% sulfur, and about 0.30 wt% nitrogen by decarbonizing or hydrodesulfurization. Upgrading costs, calculated prices of gas turbine fuel less price of high-sulfur No. 6 fuel oil, are in the range of $9.76/B to 11.16/B and are lower than the differential between prices for No. 2 fuel oil and high-sulfur No. 6 fuel oil. Fuels containing lower vanadium concentrations can not be produced from this high-metals feedstock by these processes using current

technology. Advanced technology for hydrodesulfurization of heavy oils is currently under development which could result in production of gas turbine fuels having lower metals contents and/or at lower costs.

Essentially metals-free gas turbine fuels can be produced from high-sulfur, high-metals residuals by coking followed by hydrotreating of coker distillate. However, upgrading costs exceed the price differential between No. 2 fuel oil and high-sulfur No. 6 fuel oil products, which therefore render this scheme economically infeasible.

Raw shale oil produced by surface or modified in situ retorting can be upgraded to high quality gas turbine fuel in a representative existing petroleum refinery by hydrotreating at high severity to produce a residuum suitable for charge to the existing FCC unit. Gas turbine fuel comprises the middle distillate fraction from hydrotreating followed, if necessary, by second-stage hydrotreating to ensure thermal stability. Calculated prices of gas turbine fuel are about equal to, or about $2.70/B lower than, the price of No. 2 fuel oil, depending on whether second-stage hydrotreating of middle distillate is provided or not.

III.7 Literature Cited

1. Sullivan, R. F., Stangeland, B. E., Rudy C. E., Green, D. C., and Frumkin, H. A., "Refining and Upgrading of Synfuels From Coal and Oil Shales by Advanced Catalytic Process, First Interium Report, Processing of Paraho Shale Oil, " DOE Report No. FE-2315-25, July 1978.

NEW REFINERIES TO UPGRADE FUEL

IV. 1 Summary

The costs of manufacturing gas turbine fuels of varying qualities from coal liquids, shale oils and petroleum residual oils in grass-roots facilities specifically designed for this purpose have been developed for the year 1985. Wherever applicable, they have been evaluated in the context of two distinct refining strategies: one in which impurities are removed to various levels while retaining essentially the same boiling range as the feedstock in order to maximize the product volume available as gas turbine fuel; and the other in which the boiling range of the feedstock is changed in order to make impurity removal more facile.

IV. 1.1 Summary of Cases

The feedstocks and processing options which have been examined in this task by means of complete grass-roots processing facilities are as follows:

Feedstock	Processing Option	Case Number(s)
Eastern Coal Liquid (SRC-II)	Distillate Hydrotreating @ 3 Severities	1010,1011,1020,1030
Western Coal Liquid (H-Coal)	With and Without Hydrotreating	2010,2020
Surface Retorted Shale Oil (Paraho)	Whole Oil Hydrotreating @ 3 Severities w/Diesel Fuel	3010,3011,3020,3030
	Whole Oil Hydrotreating @ 3 Severities wo/Diesel Fuel	301A,302A,303A
	Coking plus Hydrotreating @ 3 Severities	3040,3050,3060
Modified In Situ Shale Oil (Occidental)	Whole Oil Hydrotreating	4020,402A
Low-Sulfur Petroleum Residual (South Louisiana)	Hydrotreating @ 3 Severities	5010,5020,5030
	Coking plus Hydrotreating	5040
High-Sulfur Petroleum Residual (Ceuta)	Hydrotreating @ 3 Severities	6010,6020,6030
	Coking plus Hydrotreating	6040

In addition, pricing cases have been developed for the four syncrude feedstocks in order to establish market values for each of them as raw materials for the manufacture of transportation fuels. The economic summaries for all of these cases are presented in Tables IV-1 to IV-9, and block flow diagrams for each case are shown in Figures IV-1 to IV-30. They are shown in sufficient detail so that the forecast feedstock values, product prices and cost factors can be revised and the gas turbine fuel prices can be recalculated for different time periods and/or inflation rates.

As described in greater detail in Sections IV. 2 and IV. 3, a forecast 1985 total cost has been developed for the gas turbine fuel in each case. It is the price which gives a 30% return on total capital before taxes with the raw material at its estimated market value and the by-products at market prices as forecast by DRI for 1985.

Even in a grass-roots facility designed so that gas turbine fuel is the primary product, there will also be a range of by-products produced depending on the nature of the feedstock and the type of processing. Hence, a simple tabulation of the total manufacturing expenses is not necessarily a good indicator of the relative costs of manufacturing gas turbine fuels, since the costs of manufacturing by-products, such as LPG, gasoline, diesel fuel and heavy fuel oil, are interrelated with the turbine fuel treating costs. This must be taken into account when interpreting the results.

IV. 1.2 General Observations

The fuel quality/processing cost relationships developed in Task IV are used in Task V in the integration and evaluation of alternative paths from the raw materials to electric power generation. Within Task IV, the following general observations can be made:

1. Hydrotreating generally results in a lower-cost, though higher-boiling, gas turbine fuel than coking plus hydrotreating of the coker distillate to comparable purity levels. However, for removal of trace metals, particularly from high-metals petroleum residual oils, coking followed by hydrotreating is more effective, although at a higher cost.

2. The increased expense of hydrotreating at higher severities is somewhat offset by increased by-product credits, generally resulting from concomitant conversion to lighter by-products.

3. As expected, western coal liquid is less expensive than eastern coal liquid to treat to a comparable purity level, and MIS shale oil is less expensive to treat than surface retorted shale oil. However, if each feedstock is costed at its estimated market value, these differences are offset by the higher market values of western coal liquid and MIS shale oil.

4. The shale oils are generally more expensive than the coal liquids to treat to comparable purity levels.

5. Higher quality and less expensive gas turbine fuels can be produced from a low-sulfur petroleum residuum than from a high-sulfur petroleum residuum when both feedstocks are priced on the basis of viscosity and sulfur content.

IV. 2 Basis of Calculations

The basis for each case in Task IV is a complete new 1985 grass-roots refinery designed specifically to convert a syncrude or a petroleum residual oil into refined products, primarily gas turbine fuel. Each one is conceptually a stand-alone facility at an undefined location, designed to be self-sufficient in fuel, steam, and hydrogen plant feedstock and to purchase only electric power (generally less than 10 MW) and fresh water. It is not

presumed that these facilities are located near their respective raw material converting facilities. Thus no credit has been taken for any possible synergistic effects such as availability of outside fuel, hydrogen plant feedstock or heat energy.

With the exception of Cases 5010-5030 (South Louisiana vacuum bottoms), refinery fuel consists of process off-gas supplemented by treated heavy liquids. In Cases 5010-5030, low-sulfur vacuum bottoms is used directly. For hydrogen plant feedstock when there is insufficient refinery off-gas available, both steam-reforming of treated light liquids and partial oxidation of raw heavy liquids were evaluated for one coal liquid case and one shale oil case. The option resulting in the lowest gas turbine fuel price (steam reforming in both cases) was used for that and all other cases.

The economic evaluation factors used in Task IV are for the most part identical to those used in Task III and described in Table III-A. The only differences from Task III are those which result from a grass-roots facility versus additions to an existing refinery, as follows:

1. Investment is provided for all required process, tankage and utility facilities.

2. Miscellaneous off-sites are estimated as 33-1/3% of process plus tankage investment instead of 25%.

3. Working capital is included.

4. Gasoline is produced in the form of an unleaded blending component, pressurized only to the extent of available butanes and priced on an octane-barrel basis, rather than an average pool gasoline.

In each case, the grass-roots facility was sized to handle the expected output of one commercial scale raw material upgrading facility or one petroleum refinery. This was projected to be 66,600 B/CD of coal liquids,

50,000 B/CD of shale oil, 12,500 B/CD of vacuum bottoms from low-sulfur crude oil and 21,500 B/CD from high-sulfur crude oil. The choice of a specific feedstock within each category was based primarily on the availability of refinery processing data.

As in Task III, petroleum product prices are based on Data Resources Incorporated's Case CONTROL0880 for the year 1985, as are the electricity price and the natural gas price from which the ammonia price was estimated. All other investment and operating cost factors were escalated to 1985 at projected inflation rates.

IV. 3 Feedstock Pricing

In determining the potential 1985 costs of gas turbine fuels of varying qualities from various feedstocks, it is necessary to find a way to develop these costs in a manner such that they will be meaningful relative to the forecast 1985 prices for conventional petroleum products as well as to each other. The single most significant component of that cost is the feedstock price.

The price (or value or cost) of each syncrude or petroleum residual feedstock affects the quality versus cost relationship for that feedstock, since varying portions of it are consumed in the upgrading process as fuel and as hydrogen plant feedstock. In addition, the price of each feedstock is particularly important to any comparison of resulting gas turbine fuel costs from different feedstocks.

However, any attempt to estimate the cost of producing coal liquids or shale oils from their raw materials would necessarily have a great deal of uncertainty attached to it, as well as being beyond the scope of this study.

The problem of developing meaningful gas turbine fuel costs, which are greatly dependent on very uncertain feedstock costs, was resolved by determining a potential market value for each of the syncrude feedstocks as raw materials for a grass-roots facility manufacturing transportation fuels,

which are valued at the prices forecast for these conventional petroleum products. It is assumed that this will be the primary use for these syncrudes and will therefore set the market. These estimated market values are then used as the raw material costs for the subsequent cases producing gas turbine fuels of varying qualities in grass-roots facilities designed specifically for that purpose. Thus, the resulting gas turbine fuel prices used in the quality/cost relationships have a certain degree of absolute as well as relative meaning in comparison to the forecast prices of conventional petroleum products.

The flow diagrams for the four syncrude pricing cases are shown in Figures IV-1 to IV-4, and the economic summaries are presented in Table IV-1. All four of the pricing cases begin with high-severity hydrotreating, followed by naphtha pretreating (where required) and catalytic reforming to produce an average 1985 pool gasoline with a road octane number of 89.3 at a maximum of 0.27 cc TEL/gallon. The two coal liquids cases produce distillate products from the remaining hydrotreated oil. The two shale oil cases include a second hydrotreating of the distillate product in order to produce a diesel fuel of sufficient stability to meet the diesel specifications. The two shale oil cases also include fluid catalytic cracking and HF alkylation to increase gasoline yield by conversion of the hydrotreated bottoms.

The two petroleum residuals under consideration, the 1000°F vacuum bottoms from South Louisiana and Ceuta crudes, were priced as components of low-sulfur and high-sulfur No. 6 fuel oils, respectively, on a viscosity basis. Each one was cut to a viscosity of 200 SFS at 122°F with a representative cutter stock of 35° API, 0.15 wt% sulfur and 34 SUS at 100°F. The cutter stock was priced at the forecast 1985 U.S. average wholesale price for No. 2 fuel oil ($68.65/B), and the No. 6 fuel oil blends were priced at $56.03/B for low-sulfur and $53.00/B for high-sulfur fuel oil.

The resulting estimated 1985 market values at the refinery gate for all six gas turbine fuel feedstocks, consistent with the petroleum prices forecast being used in this study, are as follows:

Eastern Coal Liquid	\$51.70/B
Western Coal Liquid	\$62.70/B
Surface Retorted Shale Oil	\$53.90/B
MIS Shale Oil	\$58.00/B
South Louisiana Vacuum Bottoms	\$49.02/B
Ceuta Vacuum Bottoms	\$45.44/B

This exercise is not intended to be a definitive evaluation of these feedstocks. It merely establishes a reasonable refinery gate market value consistent with the petroleum product price forecast from which representative gas turbine fuel costs can be generated.

IV. 4 Description of Cases

IV. 4.1 Upgrading of Eastern Coal Liquid to Gas Turbine Fuel

IV. 4.1.1 Impurities Removal

For the refining strategy of impurities removal, hydrotreating of SRC-II distillate at three different severity levels was used to show the effect of quality versus cost. The hydrotreating severity used in the SRC-II pricing case (Case 1000) to manufacture on-test jet fuel was much higher than would be required to examine even the highest purity level of interest to the economic manufacture of gas turbine fuel from SRC-II liquid. It was based on a high severity run on 400°F+ SRC-II distillate by Chevron Research Company[1] and produced a hydrotreated distillate of less than 1 ppm nitrogen and about 50 ppm each of sulfur and oxygen. This is much greater than the purity level of interest in Task IV. Hence, for the gas turbine fuel product cases, processing estimates were developed by GR&DC for three lower severity operations which covered the range of 0.3-0.7 wt% nitrogen in the distillate product (Cases 1010-1030).

As in the pricing case, the SRC-II naphtha is hydrotreated separately to prepare a suitable feedstock for catalytic reforming. Since the SRC-II distillate hydrotreating is much less severe than in the pricing case, the naphtha by-product is further hydrotreated in the same naphtha hydrotreater. The hydrotreated C_5-180°F light gasoline plus the C_5+ reformate are blended and shown as an unleaded gasoline component which meets the minimum expected road octane number specification for 1985 of 87.0.

IV. 4.1.2 Hydrogen Manufacture

The catalytic reforming unit provides about 1/3 to 1/4 of the hydrogen required for both the naphtha and the distillate hydrotreaters. Two approaches were examined for manufacturing the supplemental hydrogen from in-plant raw materials: steam reforming of hydrotreated light gasoline and naphtha; and partial oxidation of raw SRC-II distillate. Partial oxidation is a more expensive process, both in its initial investment and in its operating costs, but this is offset by being able to use a lower-valued feedstock, in this case raw SRC-II distillate instead of primarily hydrotreated naphtha, a gasoline precursor.

The lowest severity SRC-II distillate hydrotreating case was developed with both steam reforming (Case 1010) and partial oxidation (Case 1011) as the processes for manufacturing hydrogen. From the economic summary shown in Table IV-2, the incremental total capital requirement for the partial oxidation case relative to the steam reforming case is $76.62 million, and the incremental return on total capital at the same turbine fuel price as in Case 1010 would be 13.9%, which is below the established criterion of 30% return on total capital before taxes. At 30% return, the turbine fuel cost is $57.75/B in Case 1011 versus $57.09/B in Case 1010.

On this basis, steam reforming of hydrotreated light gasoline and naphtha was selected as the hydrogen manufacturing process for all of the coal liquid cases requiring supplemental hydrogen. Under the project precept of directing the raw material primarily toward gas turbine use, the steam reforming case has the additional advantage of not using a turbine fuel precursor and therefore showing a higher yield of gas turbine fuel than the corresponding partial oxidation case.

IV. 4.1.3 Extensive Alteration of the Boiling Point Range

The liquid products resulting from the direct liquefaction of both eastern and western coals by the three principal coal liquefaction processes are already relatively low-boiling materials. Hence the strategy of refinery conversion processing to extensively alter the boiling point range of these materials would make economic sense only for the manufacture of lighter products such as gasoline or jet fuel and was not evaluated for the manufacture of gas turbine fuels.

IV. 4.2 Upgrading of Western Coal Liquid to Gas Turbine Fuel

The western coal liquid for which refinery processing data are most readily available is H-Coal of Wyodak coal, which is being studied extensively by Chevron Research Company[2,3] though once again in the context of manufacturing primarily transportation fuels.

The representative western coal liquid is very light and the raw 350°F+ distillate fraction already meets the minimum sulfur, nitrogen and trace-metal purity levels of interest in Task IV. However, the raw distillate is reported to have very poor oxygen stability, although hydrotreated western coal liquid has excellent oxidation stability.

Hence, two gas turbine fuel cases have been evaluated for the western coal liquid from H-Coal of Wyodak coal: one in which only the C_5-350°F naphtha is hydrotreated for subsequent catalytic reforming of the 180-350°F cut into unleaded gasoline (Case 2010); and one in which the whole liquid is

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hydrotreated and fractionated into light gasoline, naphtha for catalytic reforming and a 350°F+ distillate for gas turbine fuel (Case 2020). The raw distillate from Case 2010, while meeting the impurities criteria of Task IV, may not be a suitable gas turbine fuel because of stability problems.

IV. 4.3 Upgrading of Surface Retorted Shale Oil to Gas Turbine Fuel

Unlike coal liquids, the shale oils are generally higher boiling materials. Surface retorted shale oils contain a relatively small amount of naphtha, typically only 5-10 volume percent, and a relatively large amount of bottoms, typically 60-70 volume percent. The physical characteristics of shale oils are closer to those of petroleum liquids, although they are generally higher in sulfur, nitrogen, oxygen and arsenic contents. Because of these characteristics, the manufacturing of gas turbine fuels by both impurities removal and extensive alteration of the boiling point range are relevant in the case of shale oils.

IV. 4.3.1 Impurities Removal

The evaluation of surface retorted shale oil is based primarily on Chevron Research Company's work on the processing of Paraho shale oil.[4] The impurities removal refining strategy is examined by starting with hydrotreating of de-ashed whole shale oil, followed by hydrotreater product fractionation. Since the Chevron work was aimed primarily toward the manufacture of transportation fuels from shale oil, the level of hydrotreating severity examined by them was determined by the requirement to produce a feedstock for further conversion processing that would not deactivate fluid catalytic cracking or hydrocracking catalysts. In the present analysis, this level was taken as the most severe hydrotreating operation and two lower levels of hydrotreating were estimated by GR&DC in order to establish the fuel quality versus processing cost relationship.

After the initial whole shale oil hydrotreating step, there are still two possible approaches to gas turbine fuel production via impurities removal. One approach, applied in Cases 3010-3030, is to further hydrotreat a 350-650°F distillate cut from the initial hydrotreating step in order to meet product stability requirements for diesel fuel and to consider the 650°F+ bottoms cut as the gas turbine fuel.

An alternative approach, in the context of a facility directed primarily toward the preparation of gas turbine fuel, would be to consider the entire 350°F+ bottoms cut as a gas turbine fuel. This approach results in up to 92% conversion of shale oil into gas turbine fuel. The relative yields and qualities of gas turbine fuels which could be produced by these two approaches at the same three severity levels is shown below.

Whole Paraho Shale Oil Hydrotreating

Hydrotreating Severity	Moderate	Intermediate	High
650°F+ to Gas Turbine Fuel:	Case 3010	Case 3020	Case 3030
Yield, Vol%	45.3	41.2	35.2
Gravity, °API	25.0	27.0	29.0
Nitrogen, wt%	0.50	0.30	0.19
Sulfur, wt%	0.05	0.04	0.012
350°F+ to Gas Turbine Fuel:	Case 301A	Case 302A	Case 303A
Yield, Vol%	92.7	92.3	88.9
Gravity, °API	29.9	32.8	34.2
Nitrogen, wt%	0.54	0.34	0.11
Sulfur, wt%	0.03	0.02	0.007

In addition to significantly increasing the yield of gas turbine fuel, inclusion of the 350-650°F distillate fraction results in a gas turbine fuel of higher API gravity and lower sulfur content, but slightly higher nitrogen content.

IV. 4.3.2 Hydrogen Manufacture

In all of these Paraho shale oil hydrotreating cases, the volume of naphtha and lighter material which could be converted to a gasoline by-product is not increased substantially by the hydrotreating step. Whether or not any gasoline by-product is produced would depend on the approach taken for the manufacture of the required hydrogen.

As in the case of eastern coal liquids, two approaches to hydrogen manufacture were examined for the moderate-severity hydrotreating case: steam reforming of hydrotreated light gasoline and naphtha (Case 3010) and partial oxidation of raw Paraho shale oil (Case 3011). The results were similar to those for the eastern coal liquid - the more expensive partial oxidation hydrogen plant, despite requiring a less valuable feedstock, showed an incremental return of only 14.3% on the incremental total capital at the same turbine fuel price, which is also below the established criterion of 30% return on total capital before taxes. At 30% return, the turbine fuel cost is \$74.86/B in Case 3011 versus \$73.46 in Case 3010. Thus, steam reforming of hydrotreated light gasoline and naphtha was used in all of the Paraho shale oil hydrotreating schemes.

With hydrogen manufacture requiring 3,614-5,503 B/CD of light gasoline and naphtha, there was only 103-2,130 B/CD of hydrotreated naphtha left for possible conversion to gasoline via further hydrotreating and catalytic reforming. Further hydrotreating is required to reduce the nitrogen content of the naphtha cut to a level acceptable for catalytic reforming. These volumes were deemed to be too small for construction of pretreating and reforming units, so that except for Case 3011 (hydrogen manufacture by partial oxidation of raw shale oil), no gasoline by-product is produced. The surplus naphtha is shown as naphtha by-product at the forecast distillate price.

IV. 4.3.3 Extensive Alteration of the Boiling Point Range

A number of approaches for altering the boiling range of Paraho shale oil have been presented in the literature, primarily in the context of maximizing the production of gasoline, jet fuel and diesel fuel. The following three routes were examined by Chevron Research Company:[4]

1. Whole shale oil hydrotreating followed by fluid catalytic cracking of the hydrotreated 650°F+ bottoms.

2. Whole shale oil hydrotreating followed by hydrocracking of the 650-850°F heavy gas oil.

3. Delayed coking of the whole shale oil followed by hydrotreating of the C_5+ coker distillate.

The first two routes significantly increased the production of gasoline and jet fuel, while the third route maximized diesel fuel/No. 2 fuel oil production. Since the third route showed the lowest capital and operating costs and also gave the highest yield of potential gas turbine fuel, this route was chosen for the quality versus cost analysis for extensive alteration of the boiling point range in a grass-roots facility.

The processing schemes evaluated in Cases 3040-3060 consist of delayed coking of whole Paraho shale oil, using the Chevron Research Company data, followed by hydrotreating of the C_5+ coker distillate at each of three different severity levels. The hydrotreated oil is fractionated into a C_5-180°F light gasoline, a 180-350°F naphtha, a 350-650°F distillate cut for gas turbine fuel, and a 650°F+ bottoms for supplemental refinery liquid fuel. Surplus bottoms is shown as a low-sulfur heavy fuel oil product.

The high severity level operation (Case 3060) is based directly on Chevron's coker distillate hydrotreating data and also includes a second hydrotreating step for further nitrogen removal to enhance product stability. Cases 3040 and 3050 are based on moderate and intermediate severity hydrotreating operations estimated by GR&DC and do not include a second hydrotreating step. The stability of the turbine fuels from these operations would need to be verified.

Unlike the hydrotreating-only schemes (Cases 3010-303A), all three coking plus hydrotreating cases produce sufficient refinery gas for hydrogen plant feed and fuel and sufficient naphtha to make pretreating and catalytic reforming for gasoline production worthwhile. These cases also produce 950-5,450 B/CD of low-sulfur heavy fuel oil surplus to refinery fuel requirements.

IV. 4.4 Upgrading of Modified In Situ Shale Oil to Gas Turbine Fuel

A modified in situ (MIS) shale oil could be evaluated in the same manner as the surface retorted shale oil. However, there are very few data available on the refinery processing of MIS shale oil, so estimates had to be made on the basis of existing data on surface retorted shale oil with adjustments for the known differences in these syncrudes. For these estimates, a 23.1° API Occidental Petroleum Corp. shale oil of 1.4% nitrogen, 0.5% sulfur and 1.0% oxygen was used as the representative MIS shale oil.

Since the MIS estimates were patterned on the Paraho data and estimates, only one pair of complete grass-roots refinery schemes were developed for MIS shale oil, as Cases 4020 and 402A, which correspond to the Paraho Cases 3020 and 302A - intermediate severity hydrotreating with and without the 350-650°F distillate included in the gas turbine fuel.

IV. 4.5 Upgrading of Low-Sulfur Petroleum Residual Oil to Gas Turbine Fuel

Four cases have been evaluated on the basis of a hypothetical grass-roots facility designed to upgrade the vacuum tower bottoms from South Louisiana crude to gas turbine fuel. Cases 5010-5030 examine the refining strategy of impurities removal by means of hydrotreating units designed to reduce the vanadium content in the feedstock from 8.4 ppm to 1.7, 0.7 and less than 0.1 ppm, respectively, along with corresponding reductions in nitrogen and sulfur contents. Case 5040 examines the refining strategy of extensive alteration of the boiling point range by means of delayed coking of the vacuum tower bottoms, followed by hydrotreating of the C_5-950°F coker distillate.

In all four cases, the hydrotreating yields are based on GR&DC estimates. In the impurities removal cases, the required hydrogen is manufactured by partial oxidation of the vacuum tower bottoms feedstock. In the coking plus hydrotreating case, there are sufficient light hydrocarbons in the coker off-gas to manufacture the required hydrogen. Raw bottoms is used as the supplemental plant fuel in Cases 5010-5030, and coker off-gas is more than sufficient for plant fuel in Case 5040.

The viscosity of the C_5+ product from the hydrotreating units in Cases 5010-5030 is too high for even a residual turbine fuel (120,000-220,000 cSt at 100°F). In each case it is cut back with a representative No. 2 fuel oil product to 1100 cSt at 100°F.

IV. 4.6 Upgrading of High-Sulfur Petroleum Residual Oil to Gas Turbine Fuel

Four cases have been evaluated for upgrading a high-sulfur, high-metals petroleum residual oil to gas turbine fuel in a hypothetical grass-roots facility. The vacuum tower bottoms from Ceuta crude was chosen as representative of this type of feedstock. Hydrotreating of Ceuta vacuum tower

bottoms to reduce its vanadium content from 540 ppm to 59, 35 and 12 ppm were examined in Cases 6010, 6020 and 6030, respectively. Delayed coking followed by hydrotreating of the coker distillate to take the metals content down to essentially zero was evaluated in Case 6040.

The processing arrangements for these cases are the same as the corresponding cases for South Louisiana vacuum tower bottoms.

IV. 5 Discussion of Results

IV. 5.1 Gas Turbine Fuels from Coal Liquids

Trace metals are not significant in the coal liquids. The major impurities are nitrogen and oxygen. The three levels of SRC-II distillate hydrotreating severity produce gas turbine fuels of 0.70, 0.50 and 0.30 wt% nitrogen. They are in the heavy distillate range and have total costs of $57.09-65.79/B compared with 1985 forecast prices of $56.03/B for low-sulfur heavy fuel oil and $68.65/B for petroleum distillates. The higher costs of the better quality gas turbine fuels are offset somewhat by the increased production of by-products, as shown in the following costs calculated from the economic summaries in Table IV-2.

Case	1010	1020	1030
Turbine Fuel Nitrogen Content, Wt%	0.70	0.50	0.30
Turbine Fuel Yield, Vol% Syncrude	69.78	65.39	60.62
$/B of SRC-II Liquid			
Total Mfg. Expense, incl. ROI	13.00	15.19	19.80
Total By-Product Credit	24.86	28.25	31.62
Incremental Total Expense	Base	+2.19	+6.80
Incremental By-Product Credit	Base	+3.39	+6.76
Turbine Fuel Cost, $/B	57.09	59.10	65.79
Incremental Turbine Fuel Cost, $/B	Base	+2.01	+8.70

The higher expenses at the higher severities are offset by higher by-product credits, but these come at the cost of turbine fuel yield resulting in net increases in the costs of gas turbine fuels as quality increases.

For the western coal liquid, the raw 350°F+ distillate from H-Coal of Wyodak coal is 0.26% nitrogen and 0.07 wt% sulfur. Hydrotreating this material at relatively mild conditions reduces both the nitrogen and the sulfur contents to less than 1 ppm and converts a significant portion of the 350°F+ distillate fraction to naphtha and lighter. A summary comparison of the two cases (H-Coal distillate with and without hydrotreating), based on the economic summary shown in Table IV-3, is shown below.

Case	2010	2020
Turbine Fuel Nitrogen Content, wt%	0.26	<0.0001
Turbine Fuel Yield, Vol% Syncrude	55.83	42.27
$/B of H-Coal Liquid		
Total Mfg. Expense, incl. ROI	6.58	13.04
Total By-Product Credit	33.82	45.34
Incremental Total Expense	Base	+6.46
Incremental By-Product Credit	Base	+11.52
Turbine Fuel Cost, $/B	63.52	71.93
Incremental Turbine Fuel Cost, $/B	Base	+8.41

The expense of hydrotreating the distillate is partially offset by conversion of part of it to gasoline, which mitigates the cost increase for the gas turbine fuel.

IV. 5.2 Gas Turbine Fuels From Shale Oils

For the three levels of whole Paraho shale oil hydrotreating, two possible approaches to gas turbine fuel are considered at each severity. Cases 3010-3030 have a second hydrotreating step for the 350-650°F distillate to produce a stable, on-test diesel fuel product at $68.65/B. The hydrotreated 650°F+ bottoms streams from the three cases are light residual-range materials with very low sulfur contents (0.01-0.05 wt%), but their calculated costs are higher than the forecast petroleum distillate price, as shown in the following table developed from the economic summaries in Table IV-4.

Case	3010	3020	3030
Turbine Fuel Nitrogen Content, wt%	0.50	0.30	0.19
Turbine Fuel Yield, Vol% Syncrude	45.28	41.23	35.25
$/B of Paraho Shale Oil			
Total Mfg. Expense, incl. ROI	21.63	23.56	26.41
Total By-Product Credit	42.27	46.30	51.38
Incremental Total Expense	Base	+1.93	+4.78
Incremental By-Product Credit	Base	+4.03	+9.11
Turbine Fuel Cost, $/B	73.46	75.57	82.07
Incremental Turbine Fuel Cost, $/B	Base	+2.11	+8.61

The high cost of these gas turbine fuels is probably a result of the high cost of producing the diesel fuel at a predetermined price having to be absorbed by the relatively small amount of gas turbine fuel.

Cases 301A-303A examine the same three whole shale oil hydrotreating severities, but with the entire 350°F+ bottoms going to gas turbine fuel and elimination of the extra distillate hydrotreating step. These gas turbine fuels are lighter and have even lower sulfur contents. The nitrogen contents are barely affected, since the nitrogen is fairly evenly distributed in the hydrotreated oil. A summary comparison of these cases, based on the economic summaries in Table IV-5, is shown below.

Case	301A	302A	303A
Turbine Fuel Nitrogen Content, Wt%	0.54	0.34	0.11
Turbine Fuel Yield, Vol% Syncrude	92.68	92.31	88.90
$/B of Paraho Shale Oil			
Total Mfg. Expense, incl. ROI	18.64	21.41	24.56
Total By-Product Credit	9.26	10.92	14.43
Incremental Total Expense	Base	+2.77	+5.92
Incremental By-Product Credit	Base	+1.66	+5.17
Turbine Fuel Cost, $/B	68.27	69.76	72.02
Incremental Turbine Fuel Cost, $/B	Base	+1.49	+3.75

The resulting gas turbine fuel costs, ranging from $68.27 to $72.02/B, are $5.19-10.05/B below the costs for the heavier gas turbine fuels from Cases 3010-3030. This is due to the hydrotreated distillate being included directly in the gas turbine fuel instead of being further hydrotreated and then priced at only $68.65/B as diesel fuel.

Cases 3040-3060, which examine the refining strategy of extensive alteration of the boiling point range by means of delayed coking followed by hydrotreating of the coker distillate, result in significantly higher gas turbine fuel costs at comparable quality levels. The results are summarized in the following table based on the economic summaries in Table IV-6.

Case	3040	3050	3060
Turbine Fuel Nitrogen Content, wt%	0.50	0.30	0.06
Turbine Fuel Yield, Vol% Syncrude	56.85	57.74	58.86
$/B of Paraho Shale Oil			
Total Mfg. Expense, incl. ROI	16.98	17.71	20.46
Total By-Product Credit	22.56	23.65	24.62
Incremental Total Expense	Base	+0.73	+3.48
Incremental By-Product Credit	Base	+1.09	+2.06
Turbine Fuel Cost, $/B	85.01	83.06	84.51
Incremental Turbine Fuel Cost, $/B	Base	-1.95	-0.50

Although this approach requires less investment, consumes less hydrogen and generally has lower operating costs, these advantages are more than offset by the lower yields of gas turbine fuel, and the lower by-product credits relative to the hydrotreating-only cases. In these cases, the gas turbine fuel cost actually decreases with increasing purity, though not as much in Case 3060 because that case has a second hydrotreater to enhance product stability.

The MIS shale oil syncrude is lower boiling and has less impurities than the surface retorted shale oil. Since the processing estimates were based on the corresponding data for Paraho shale oil, only two complete cases were calculated. They show the expected results of higher gas turbine fuel yields at lower operating costs, as shown in the following summary comparison.

Case	4020	402A
Turbine Fuel Nitrogen Content, wt%	0.30	0.30
Turbine Fuel Yield, Vol% Syncrude	44.17	92.15
$/B of MIS Shale Oil		
Total Mfg. Expense, incl. ROI	18.45	16.45
Total By-Product Credit	42.52	9.04
Turbine Fuel Cost, $/B	76.81	70.70

Comparison to Paraho Shale Oil Cases, $/B

Incremental Feedstock Cost	+4.10	+4.10
Incremental Mfg. Expense, incl. ROI	-5.11	-4.96
Incremental By-Product Credit	-3.78	-1.88
Incremental Turbine Fuel Cost	+1.24	+0.94

However, because the MIS shale oil feedstock is more valuable than Paraho shale oil as a raw material for transportation fuels, the resulting gas turbine fuel costs are slightly higher in total cost. The same relationship would apply for the remaining MIS cases which were not evaluated.

IV. 5.3 Gas Turbine Fuels From Petroleum Residual Oils

For the petroleum residual oils, trace metals, particularly vanadium, are the impurities of greatest concern. Small grass-roots facilities, designed primarily to reduce the metals contents, were evaluated for representative low-sulfur (and low metals) and high-sulfur (and high metals) vacuum tower bottoms. Results for the South Louisiana vacuum bottoms cases reported in Table IV-8 are summarized below.

Case	Hydrotreating Only 5010	5020	5030	Coking plus Htr. 5040
Turbine Fuel Vanadium Content, ppm	1.3	0.5	0.05	0.0
Turbine Fuel Yield without Cutter, Vol%	102.40	102.56	102.58	76.18
Turbine Fuel Yield with Cutter, Vol%	138.63	136.18	135.05	76.18
$/B of Vacuum Tower Bottoms				
Total Mfg. Expenses, incl ROI	14.72	15.29	15.85	14.70
Cutter Stock Cost	24.28	22.50	21.73	-
Total By-Product Credit	2.63	2.77	2.95	14.81
Incremental Total Expense	Base	+0.57	+1.13	-0.02
Incremental Cutter Stock Cost	Base	-1.78	-2.55	-24.28
Incremental By-Product Credit	Base	+0.14	+0.32	+12.18
Turbine Fuel Cost, $/B	61.59	61.71	61.94	64.20
Incremental Turbine Fuel Cost, $/B	Base	+0.12	+0.35	+2.61

Because the metals content of the South Louisiana vacuum bottoms is low, the net costs for going to slightly higher hydrotreating severities are small. In the coking case, the by-product credit is not high enough to offset the reduced gas turbine fuel yield.

The high-sulfur petroleum residual oil hydrotreating cases require much higher investments and operating costs to accomodate the significantly higher metals content of the feedstock. Results for the Ceuta vacuum bottoms cases reported in Table IV-9 are summarized below:

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Case	Hydrotreating Only 6010	6020	6030	Coking plus Htr. 6040
Turbine Fuel Vanadium Content, ppm	49	30	11	0
Turbine Fuel Yield without Cutter, Vol%	99.44	99.65	99.07	75.74
Turbine Fuel Yield with Cutter, Vol%	118.53	117.82	115.29	75.74
$/B of Vacuum Tower Bottoms				
Total Mfg. Expense, incl. ROI	25.03	25.98	27.37	15.69
Cutter Stock Cost	13.18	12.51	11.24	-
Total By-Product Credit	5.19	5.41	5.72	8.12
Incremental Total Expense	Base	+0.95	+2.34	-9.34
Incremental Cutter Stock Cost	Base	-0.67	-1.91	-13.18
Incremental By-Product Credit	Base	+0.22	+0.53	+2.93
Turbine Fuel Cost, $/B	66.19	66.65	67.93	69.99
Incremental Turbine Fuel Cost, $/B	Base	+0.46	+1.74	+3.80

The same relationships hold among these cases as among the South Louisiana vacuum bottoms cases. The resulting gas turbine fuels, in addition to being inferior in quality, are higher in cost than the corresponding gas turbine fuels from the South Louisiana vacuum bottoms because the higher manufacturing expenses are not completely offset by lower feedstock costs. The feedstocks were priced at their estimated market values on the basis of sulfur content and viscosity.

IV. 6 Literature Cited

1. Sullivan, R. F., and H. A. Frumken, "Refining and Upgrading of Synfuels from Coal and Oil Shales by Advanced Catalytic Processes, Third Interim Report, Processing of SRC-II Syncrude," DOE Report No. FE-2315-47, April 30, 1980.

2. O'Rear, D. J., R. F. Sullivan and B. E. Stangeland, "Catalytic Upgrading of H-Coal Syncrudes," 179th National Meeting, American Chemical Society, Houston, Texas, March 23-28, 1980.

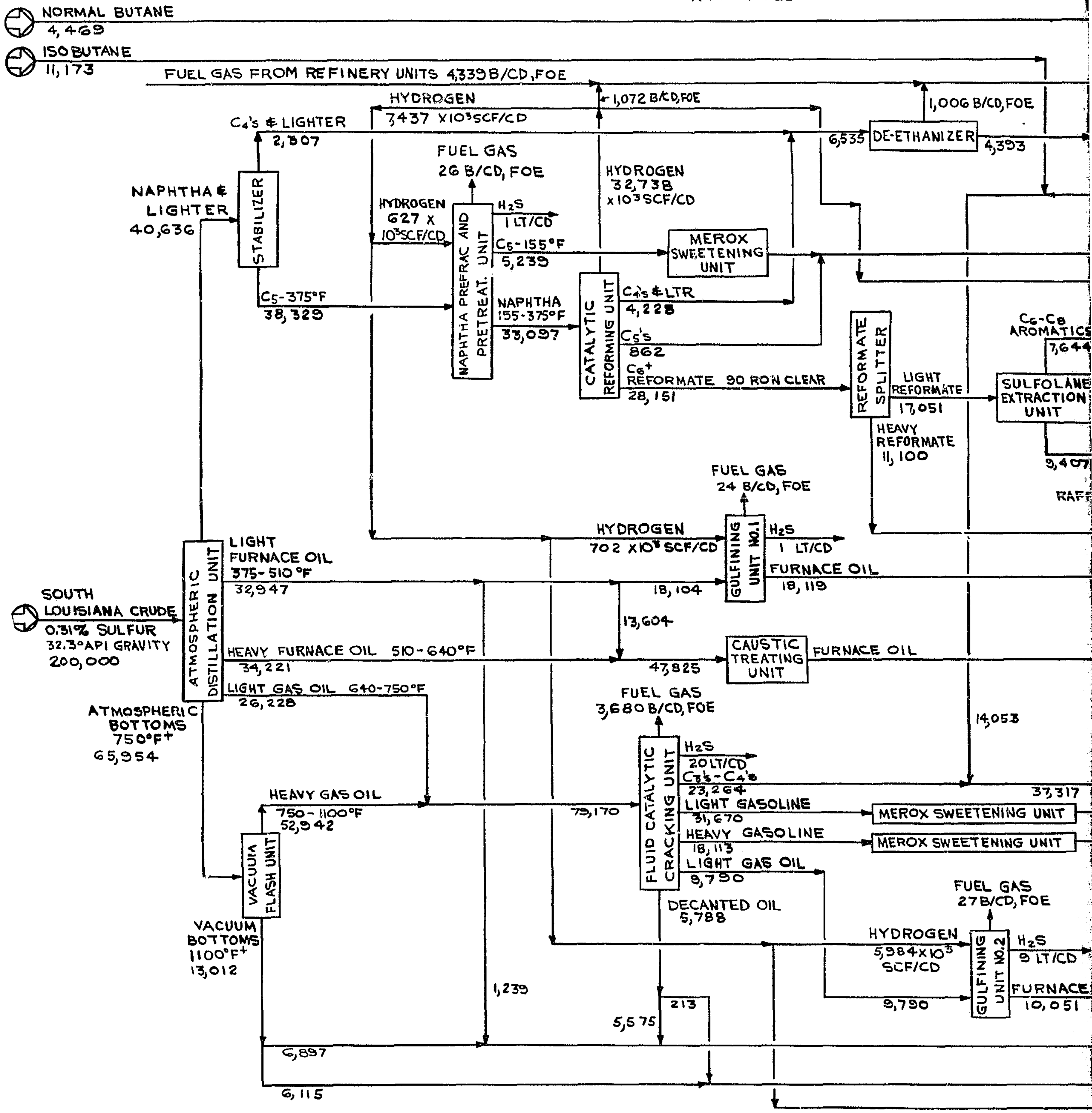
3. Sullivan, R. F., D. J. O'Rear and B. E. Stangeland, "Catalytic Hydroprocessing of SRC-II and H-Coal Syncrudes for BTX Feedstocks," 180th National Meeting, American Chemical Society, San Francisco, California, August 24-29, 1980.

4. Sullivan, R. F., B. E. Stangeland, C. E. Rudy, D. C. Green and H. A. Frumken, "Refining and Upgrading of Synfuels from Coal and Oil Shales by Advanced Catalytic Processes, First Interim Report, Processing of Paraho Shale Oil," DOE Report No. FE-2315-25, July, 1978.

APPENDIX A

SCHEMATIC FLOW DIAGRAMS

FIGURE III-1
REPRESENTIVE EXISTING REFINERY CHARGING LOW-SULFUR
BASE CASE - CASE 1.00
NO.6 FUEL OIL PRODUCTION



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NOTE: ALL FLOW RATES IN B/CD EXCEPT AS OTHERWISE SHOWN.

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FIGURE III-1
ING REFINERY CHARGING LOW-SULFUR CRUDE OIL
BASE CASE - CASE 1.00
O.6 FUEL OIL PRODUCTION

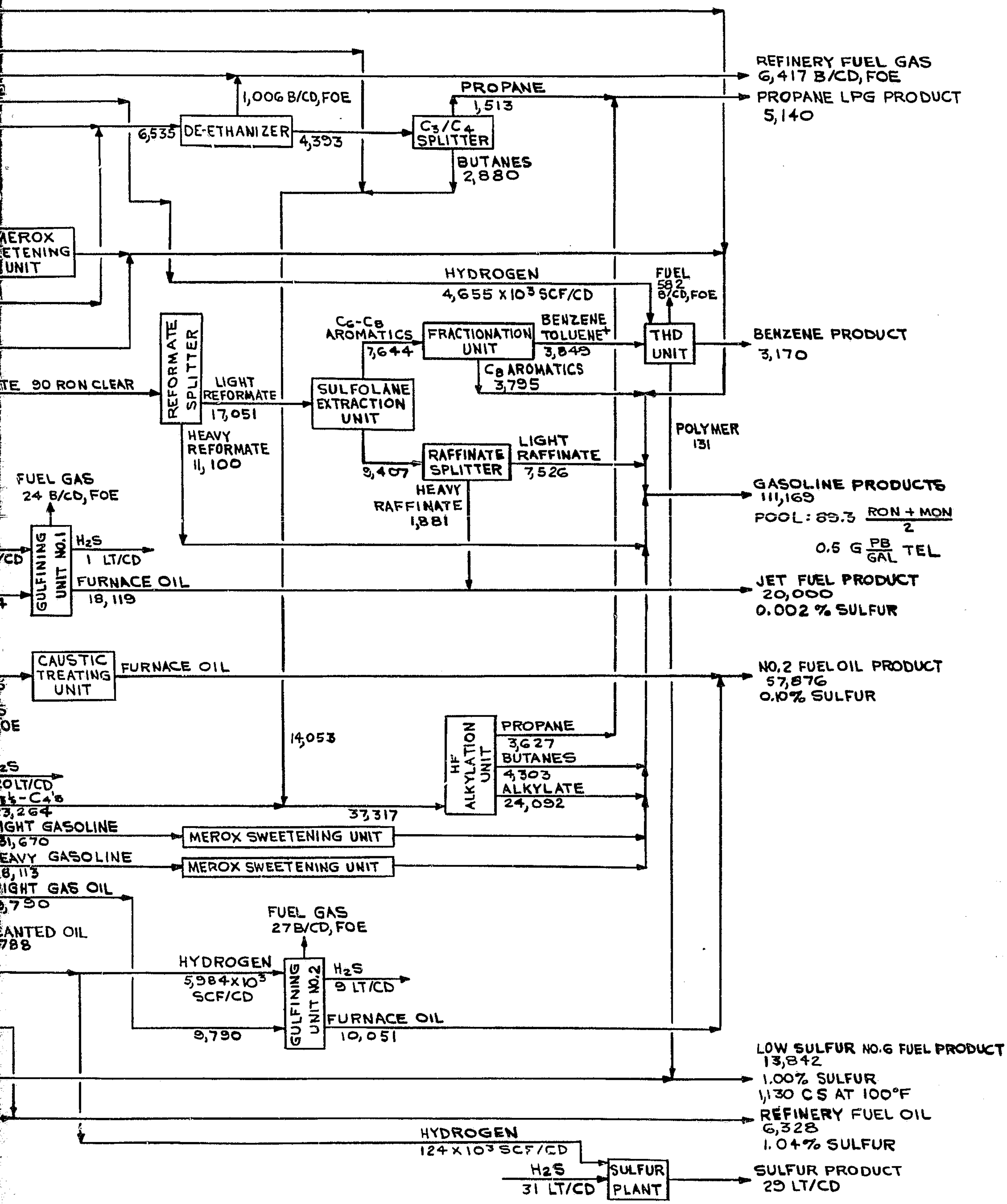
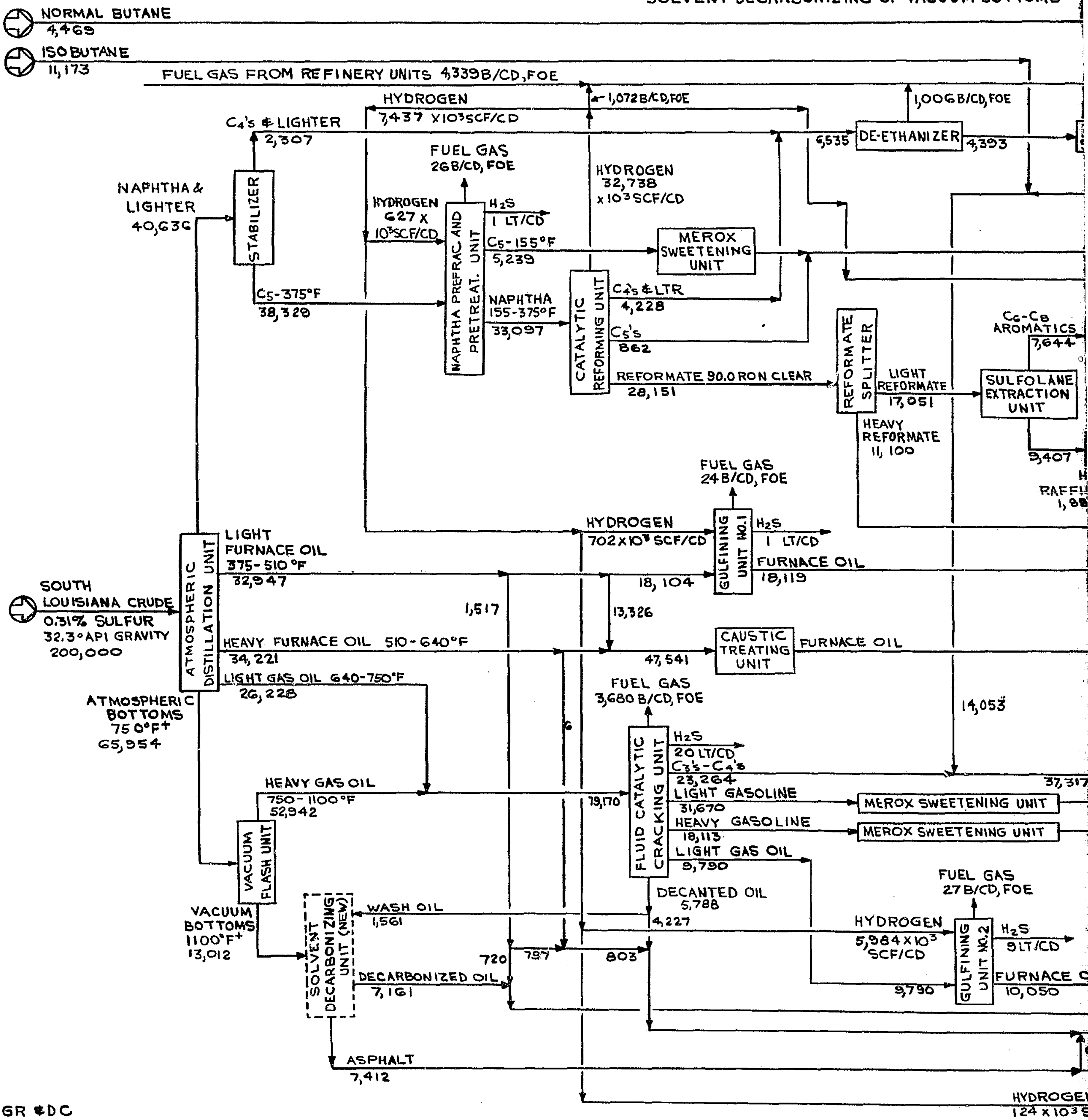


FIGURE III-2
REPRESENTIVE EXISTING REFINERY CHARGING LOW-SULFUR C
GAS TURBINE FUEL PRODUCTION – CASE 1.10
SOLVENT DECARBONIZING OF VACUUM BOTTOMS



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NOTE: ALL FLOW RATES IN B/CD EXCEPT AS OTHERWISE SHOWN.

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FIGURE III-2
ING REFINERY CHARGING LOW-SULFUR CRUDE OIL
TURBINE FUEL PRODUCTION — CASE 1.10
/ENT DECARBONIZING OF VACUUM BOTTOMS

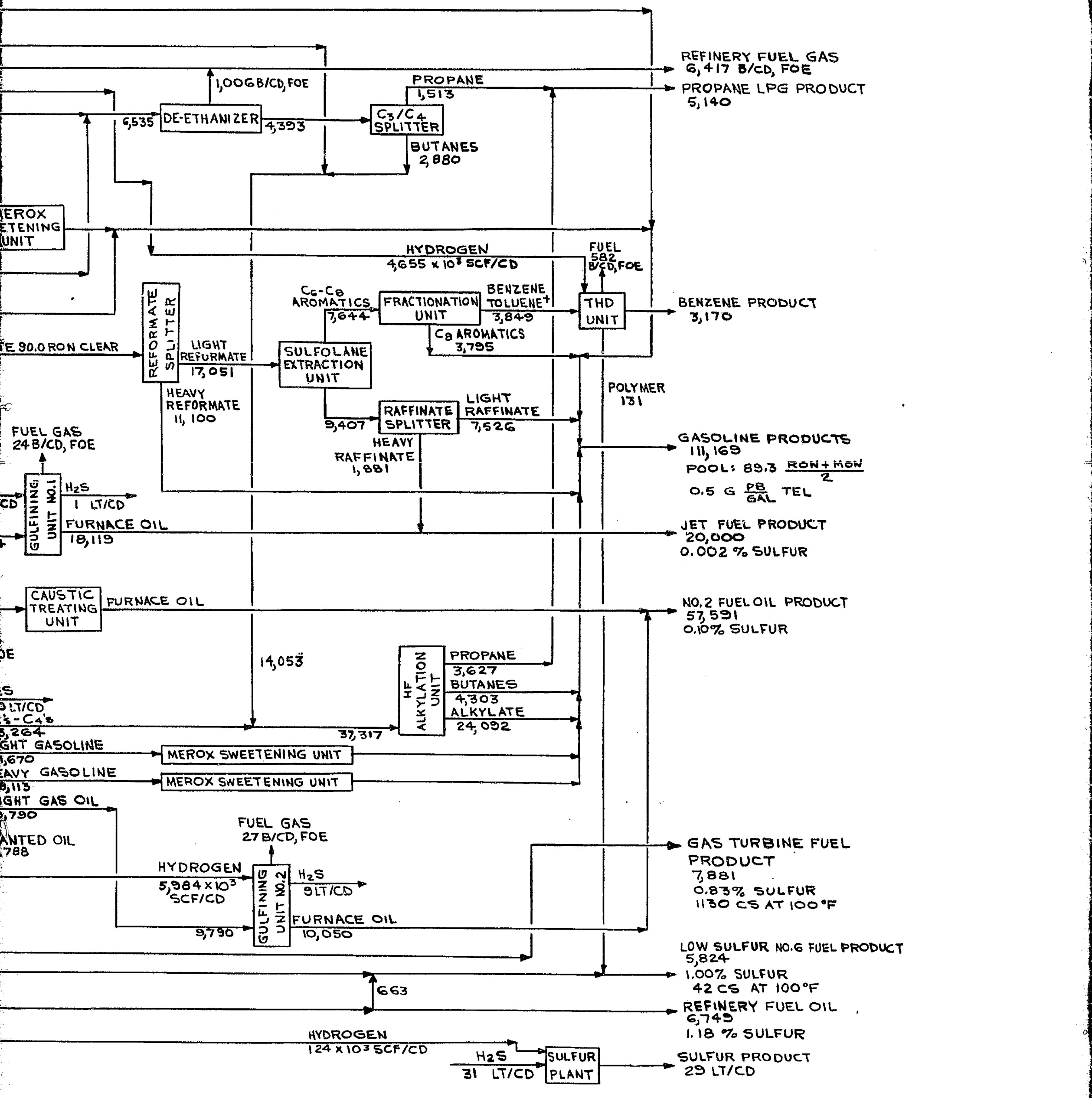

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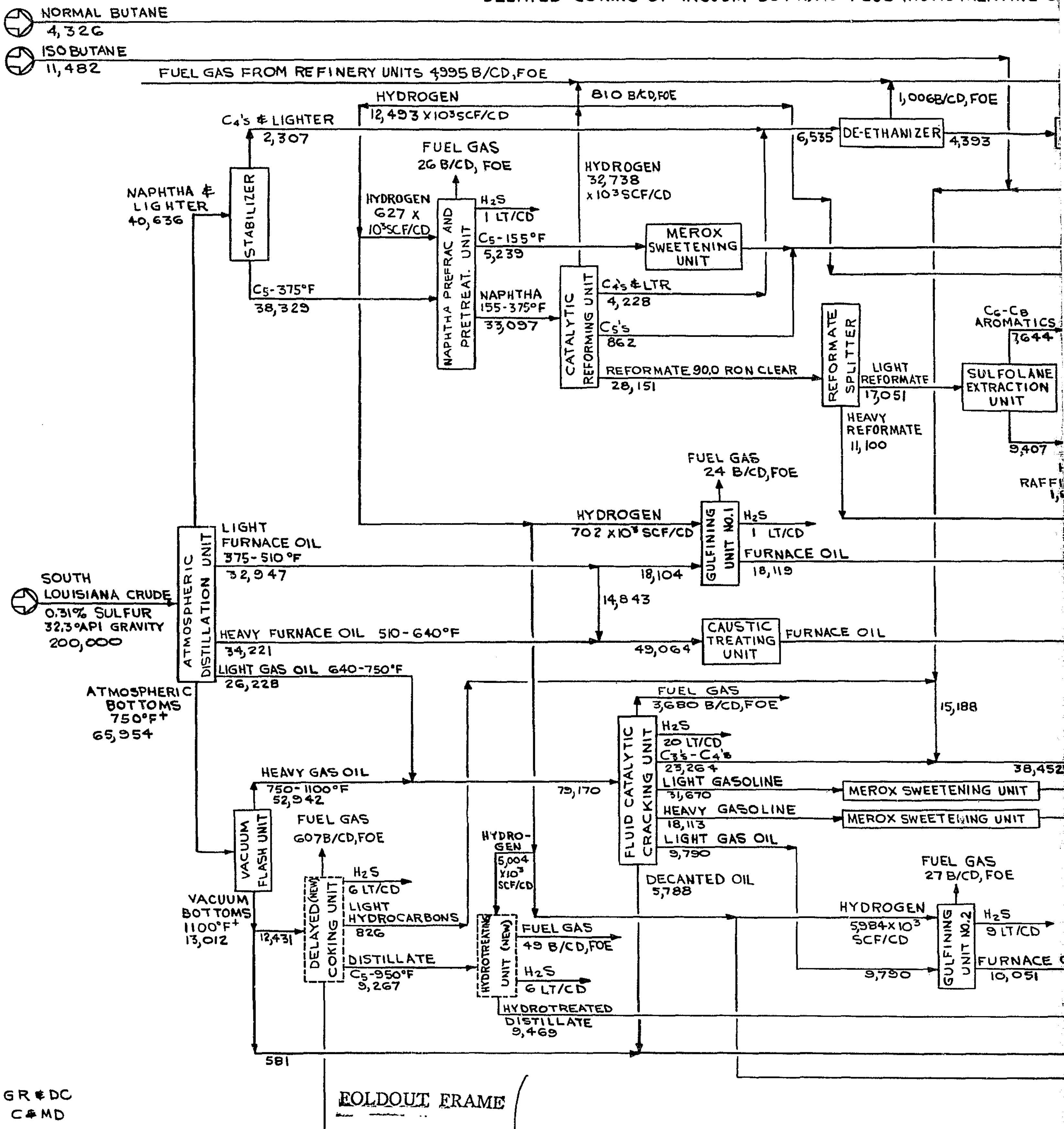
FIGURE III-3
REPRESENTIVE EXISTING REFINERY CHARGING LOW-SULFUR
GAS TURBINE FUEL PRODUCTION – CASE 1.21
DELAYED COKING OF VACUUM BOTTOMS PLUS HYDROTREATING O



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NOTE: ALL FLOW RATES IN B/CD EXCEPT OTHERWISE SHOWN.

FIGURE III-3
STING REFINERY CHARGING LOW-SULFUR CRUDE OIL
S TURBINE FUEL PRODUCTION - CASE 1.21
F VACUUM BOTTOMS PLUS HYDROTREATING OF COKER C_5-950°F DISTILLATE

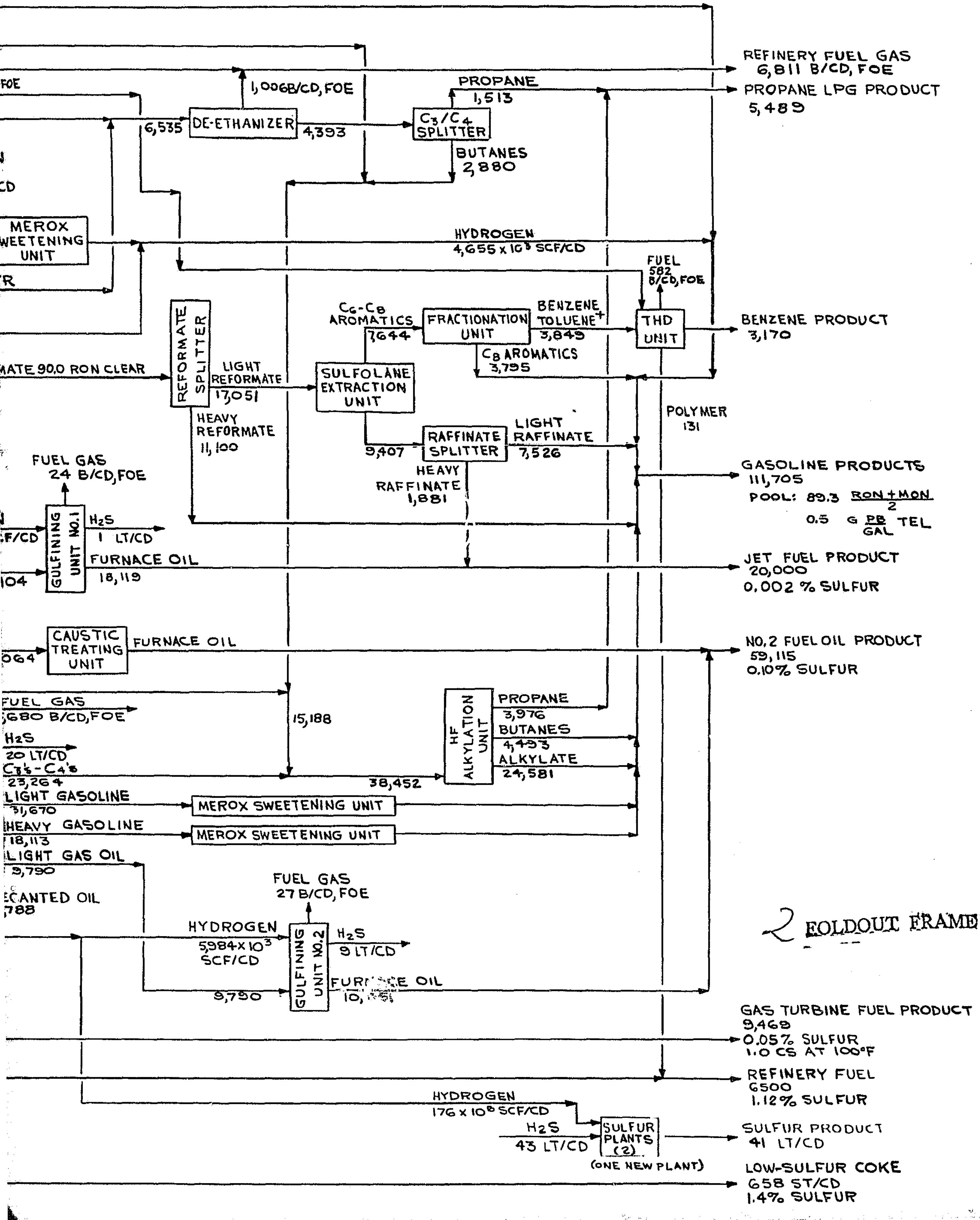
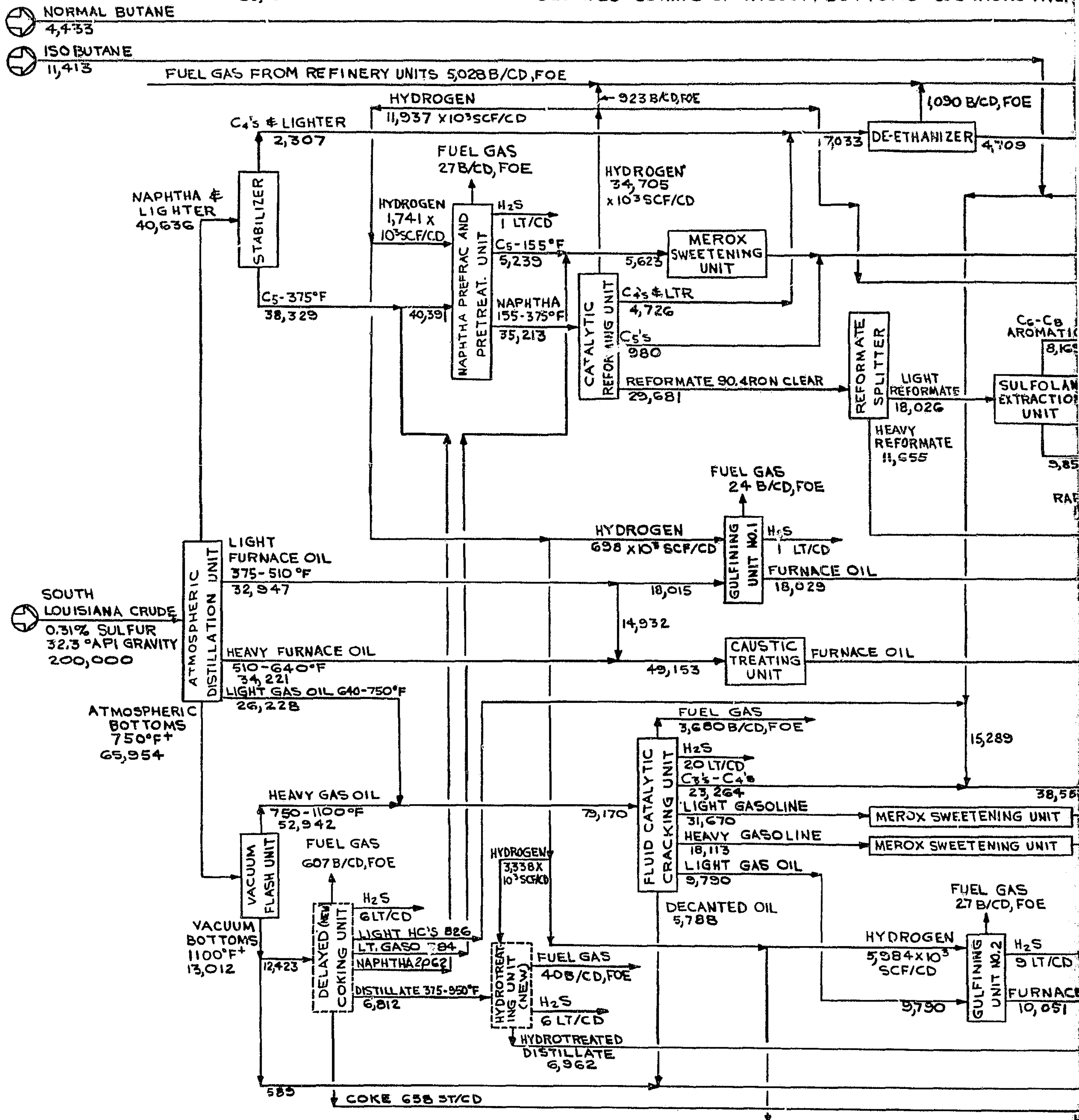


FIGURE III-4
REPRESENTIVE EXISTING REFINERY CHARGING LOW-SULFUR
GAS TURBINE FUEL PRODUCTION – CASE 1.2
DELAYED COKING OF VACUUM BOTTOMS PLUS HYDROTREA



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NOTE: ALL FLOW RATES IN B/CD EXCEPT AS OTHERWISE SHOWN.

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FIGURE III-4
IVE EXISTING REFINERY CHARGING LOW-SULFUR CRUDE OIL
GAS TURBINE FUEL PRODUCTION – CASE 1.22
D COKING OF VACUUM BOTTOMS PLUS HYDROTREATING OF COKER 375-950 °F DISTILLATE

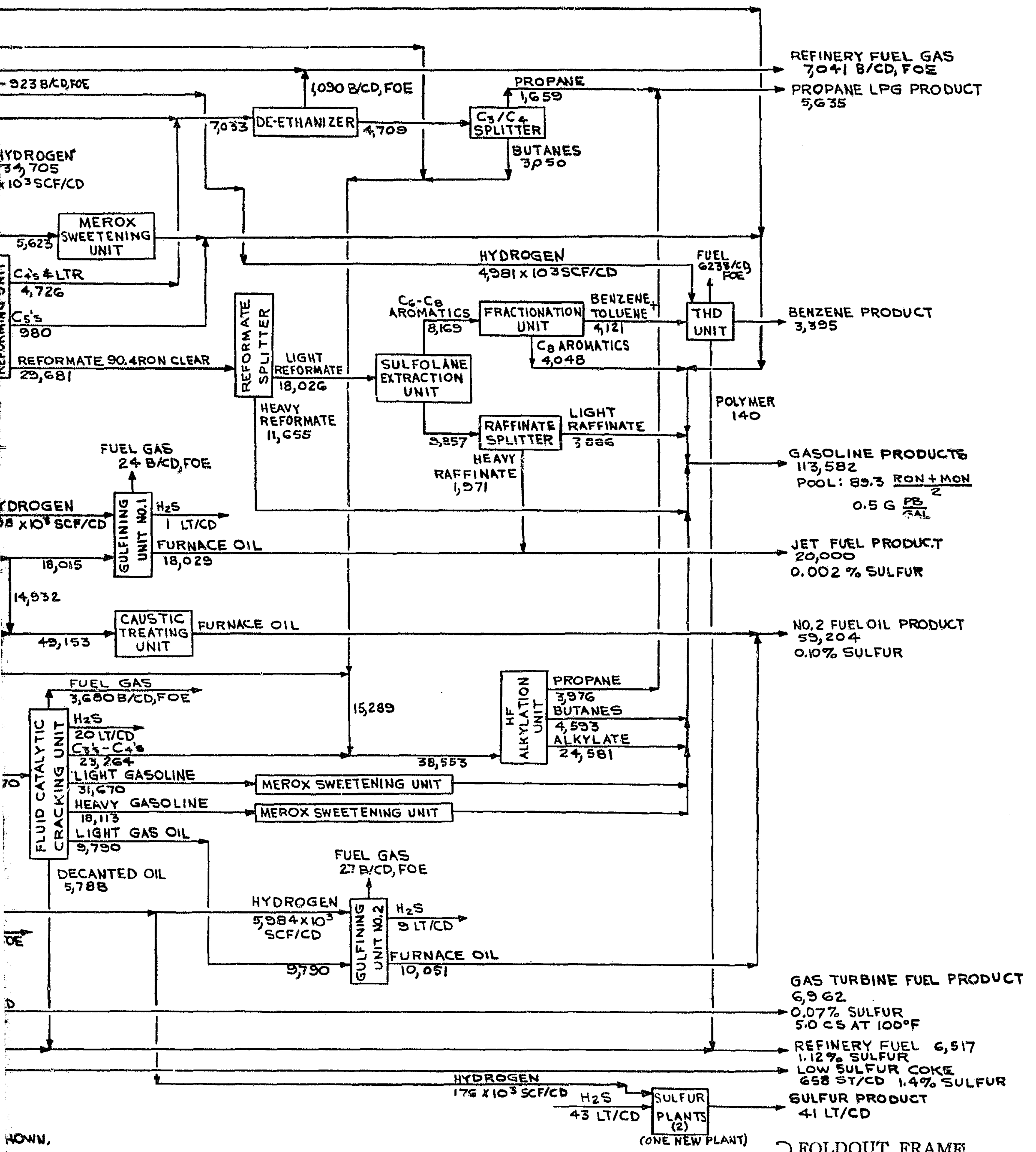

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FIGURE III-5
REPRESENTIVE EXISTING REFINERY CHARGING LOW-SULFUR
GAS TURBINE FUEL PRODUCTION - CASE 1,2
DELAYED COKING OF VACUUM BOTTOMS PLUS HYDROTREATI

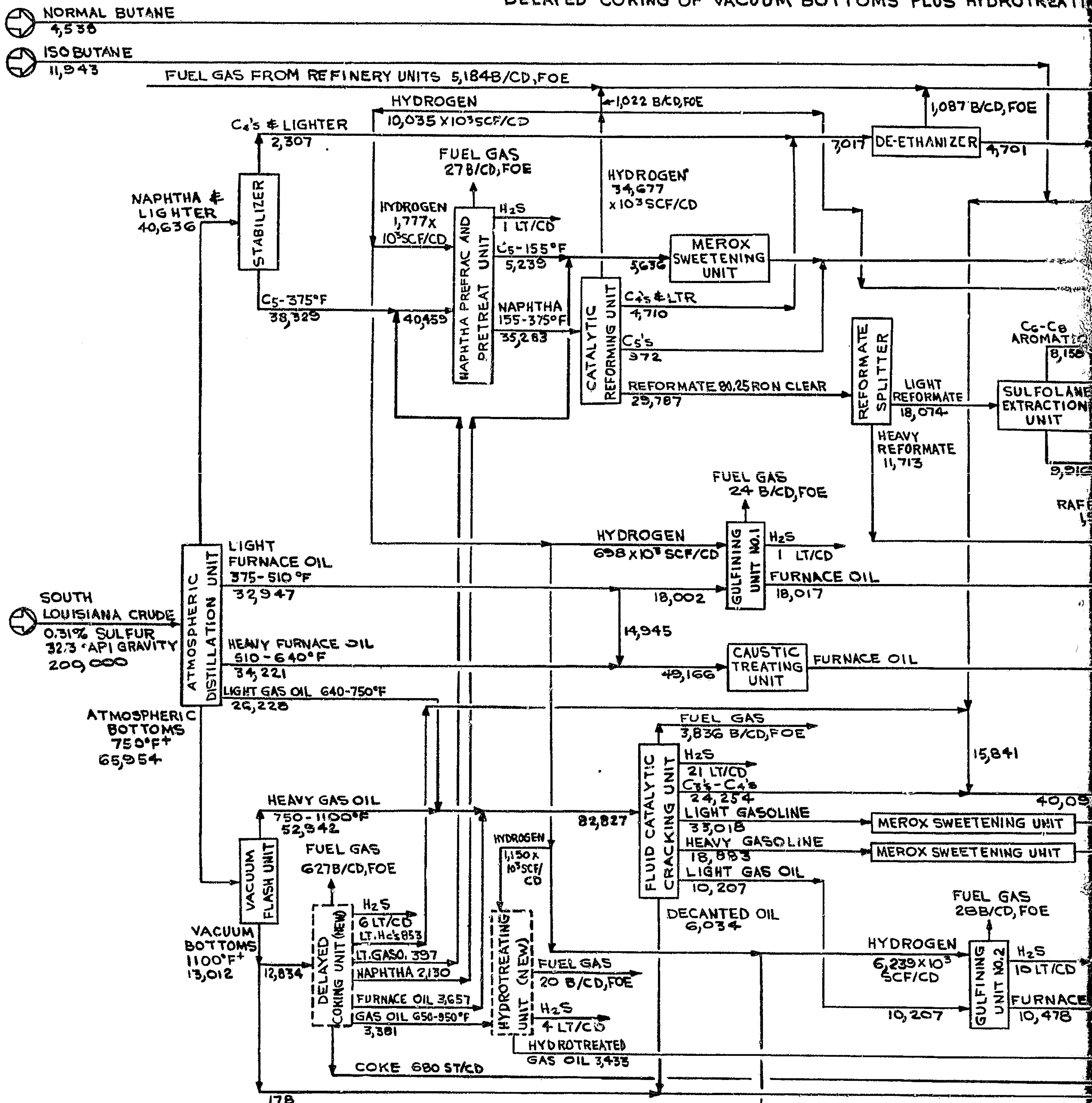

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FIGURE III-5

NG REFINERY CHARGING LOW-SULFUR CRUDE OIL
TURBINE FUEL PRODUCTION - CASE 1.23
VACUUM BOTTOMS PLUS HYDROTREATING OF COKER 650-950°F GAS OIL

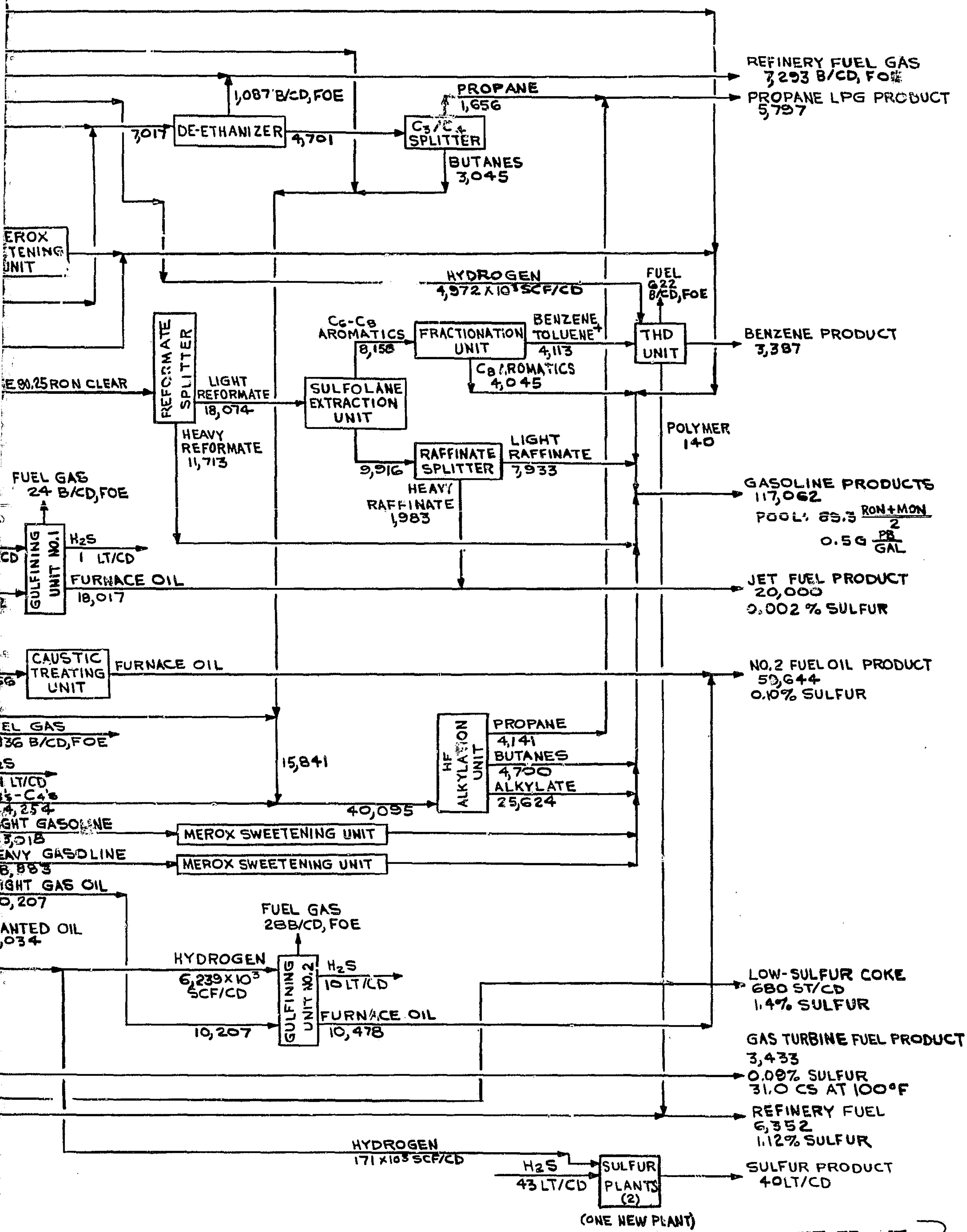

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FIGURE III-6
REPRESENTIVE EXISTING REFINERY CHARGING LOW-SULFUR
PRODUCTION OF GAS TURBINE FUEL - CASE 1.31
HYDRODESULFURIZATION OF VACUUM BOTTOMS AT MODERA

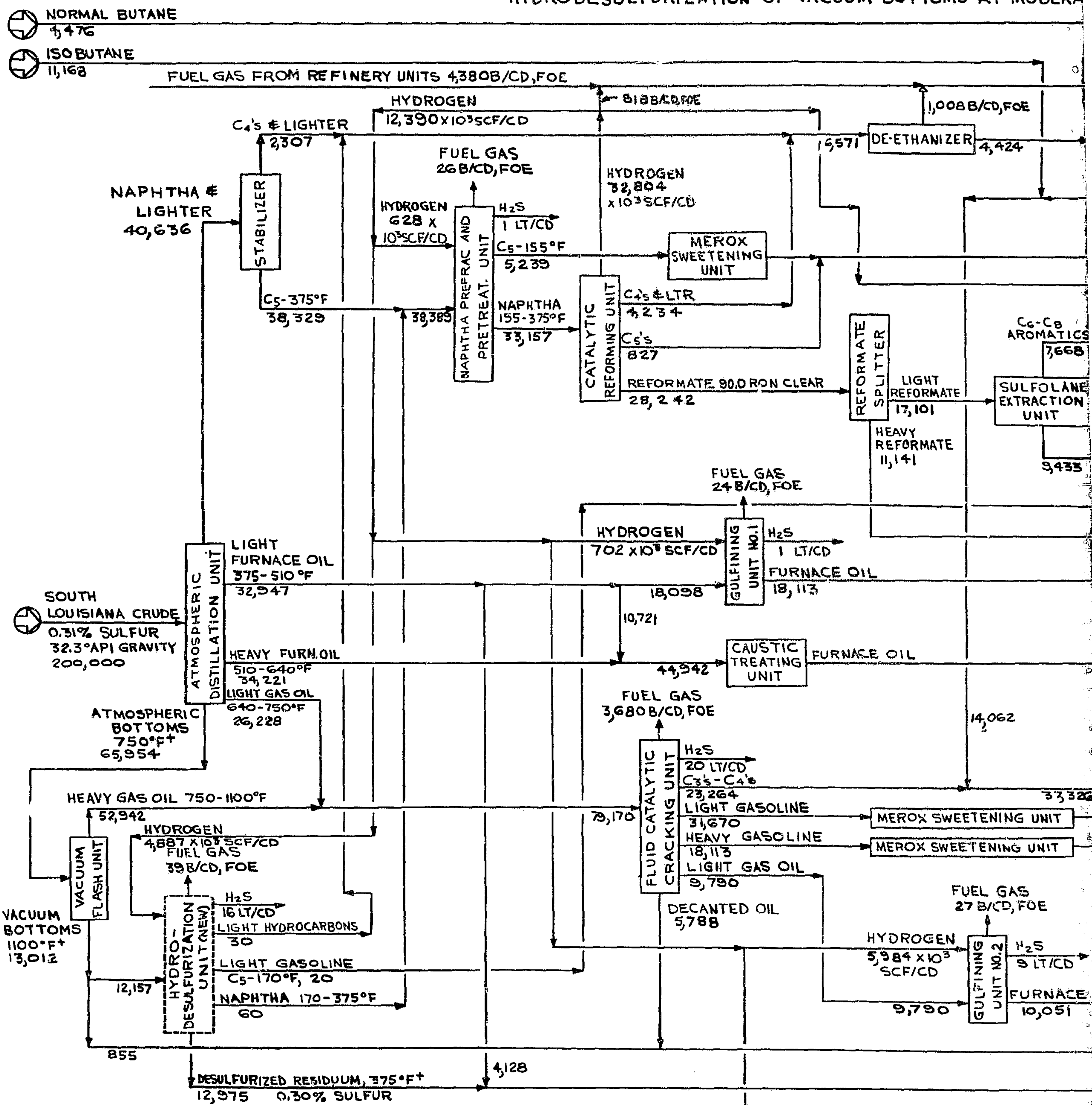

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FIGURE III-6
...NTIVE EXISTING REFINERY CHARGING LOW-SULFUR CRUDE OIL
...DUCTION OF GAS TURBINE FUEL – CASE 1.31
...ESULFURIZATION OF VACUUM BOTTOMS AT MODERATE SEVERITY

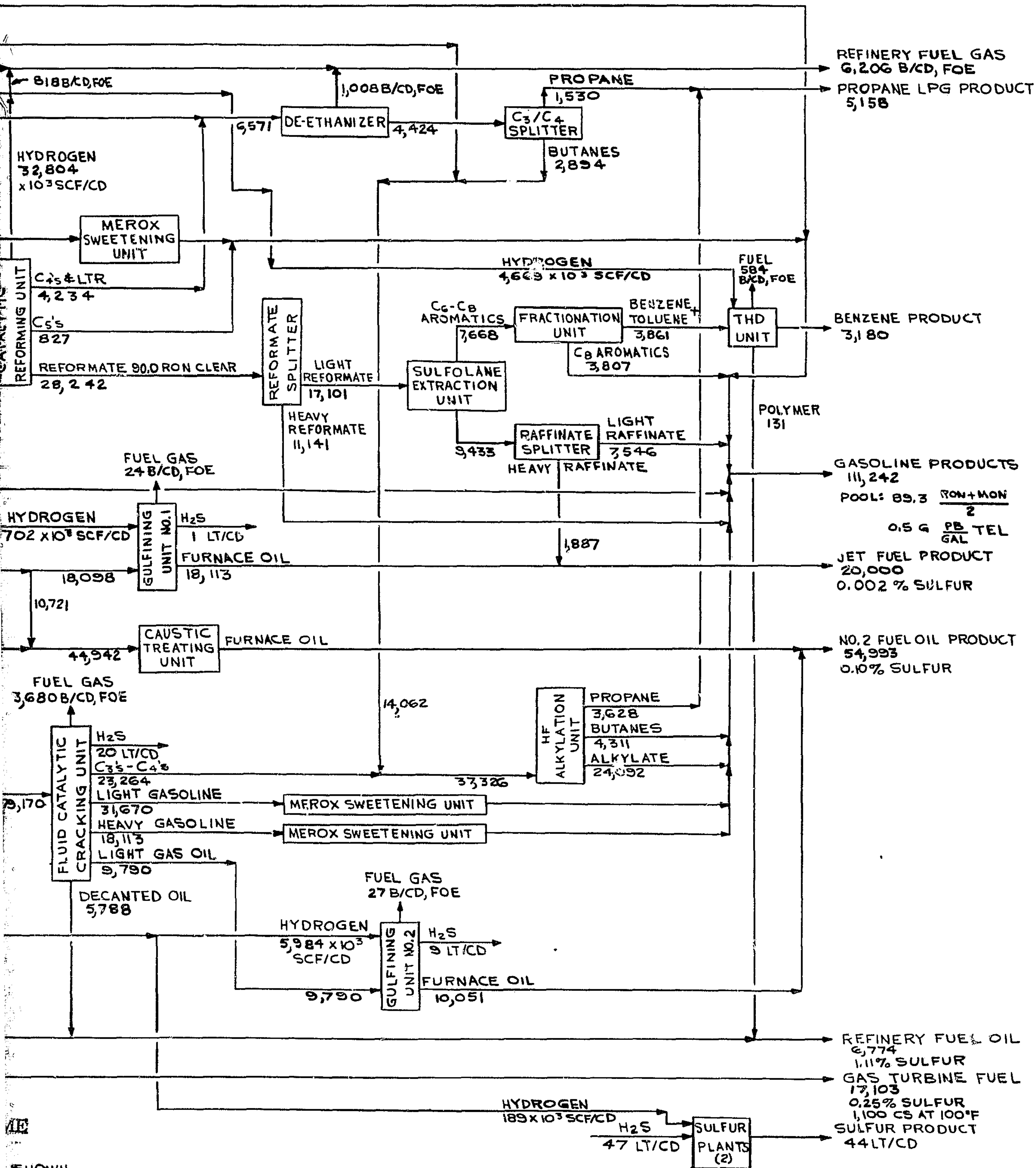

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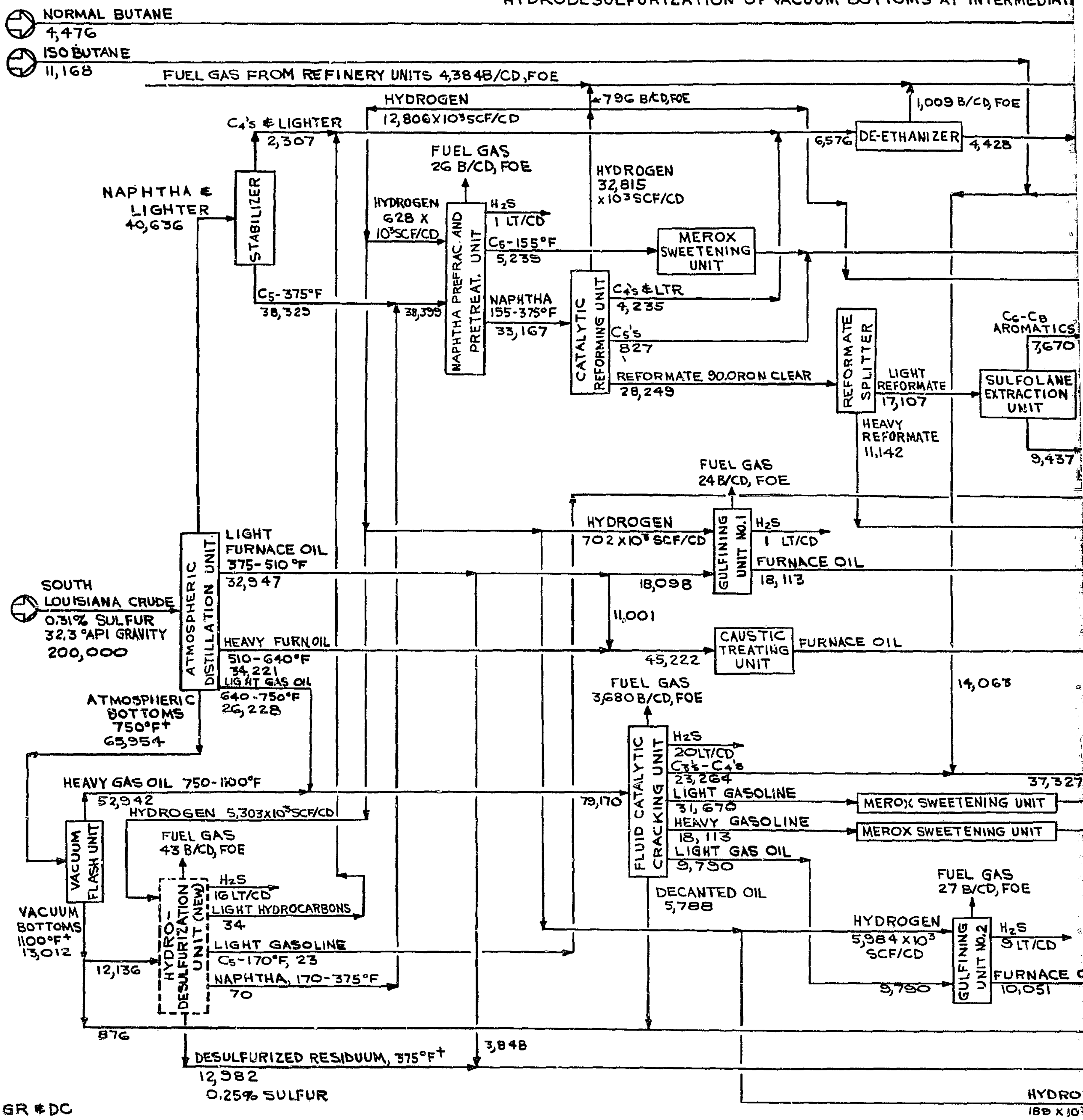
FIGURE III-7
REPRESENTIVE EXISTING REFINERY CHARGING LOW-SULFUR
PRODUCTION OF GAS TURBINE FUEL - CASE 1.32
HYDRODESULFURIZATION OF VACUUM BOTTOMS AT INTERMEDIAT



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NOTE: ALL FLOW RATES IN B/CD EXCEPT AS OTHERWISE SHOWN.

FIGURE III - 7

EXISTING REFINERY CHARGING LOW-SULFUR CRUDE OIL
OF GAS TURBINE FUEL - CASE 1.32
FURIZATION OF VACUUM BOTTOMS AT INTERMEDIATE SEVERITY

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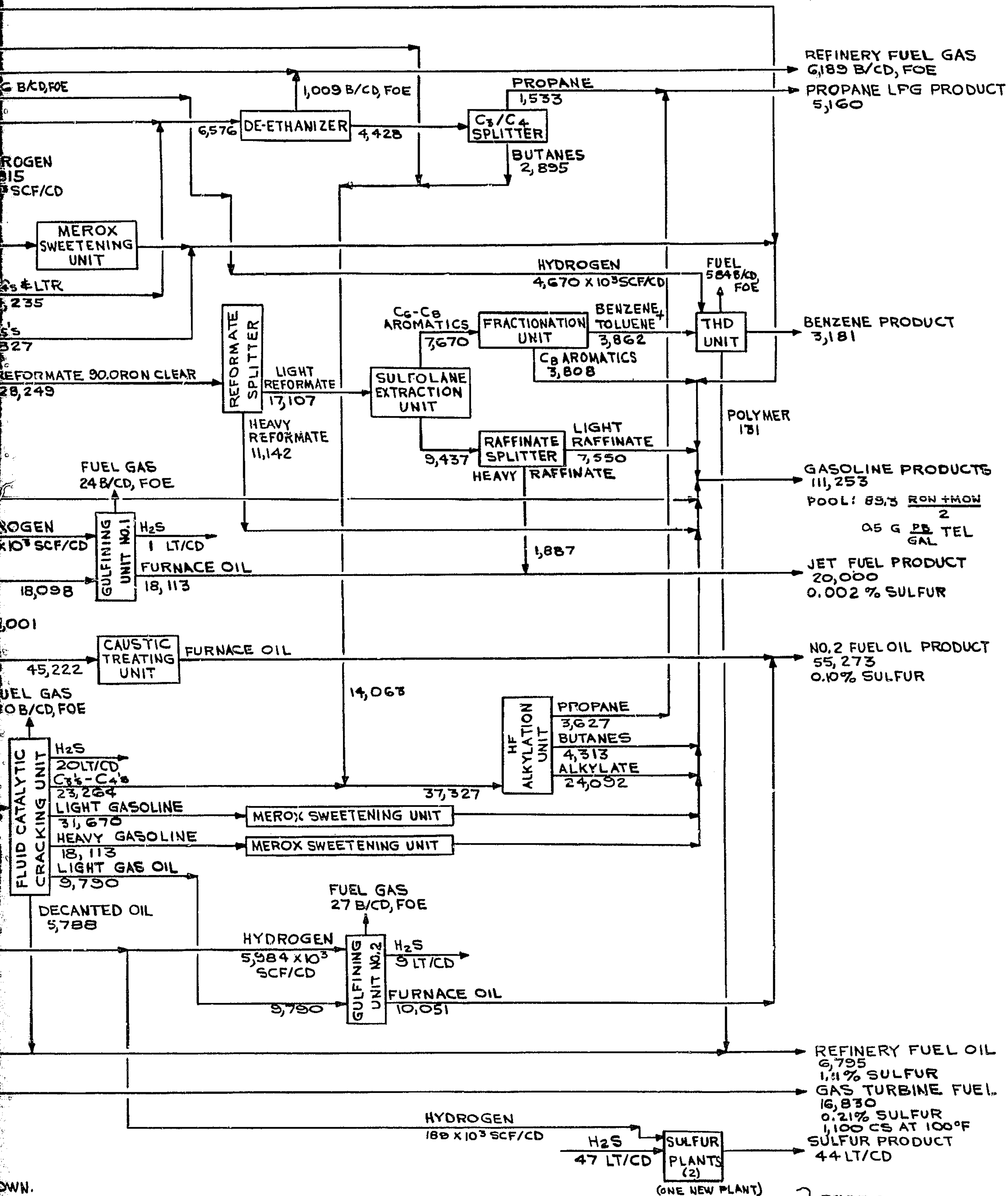

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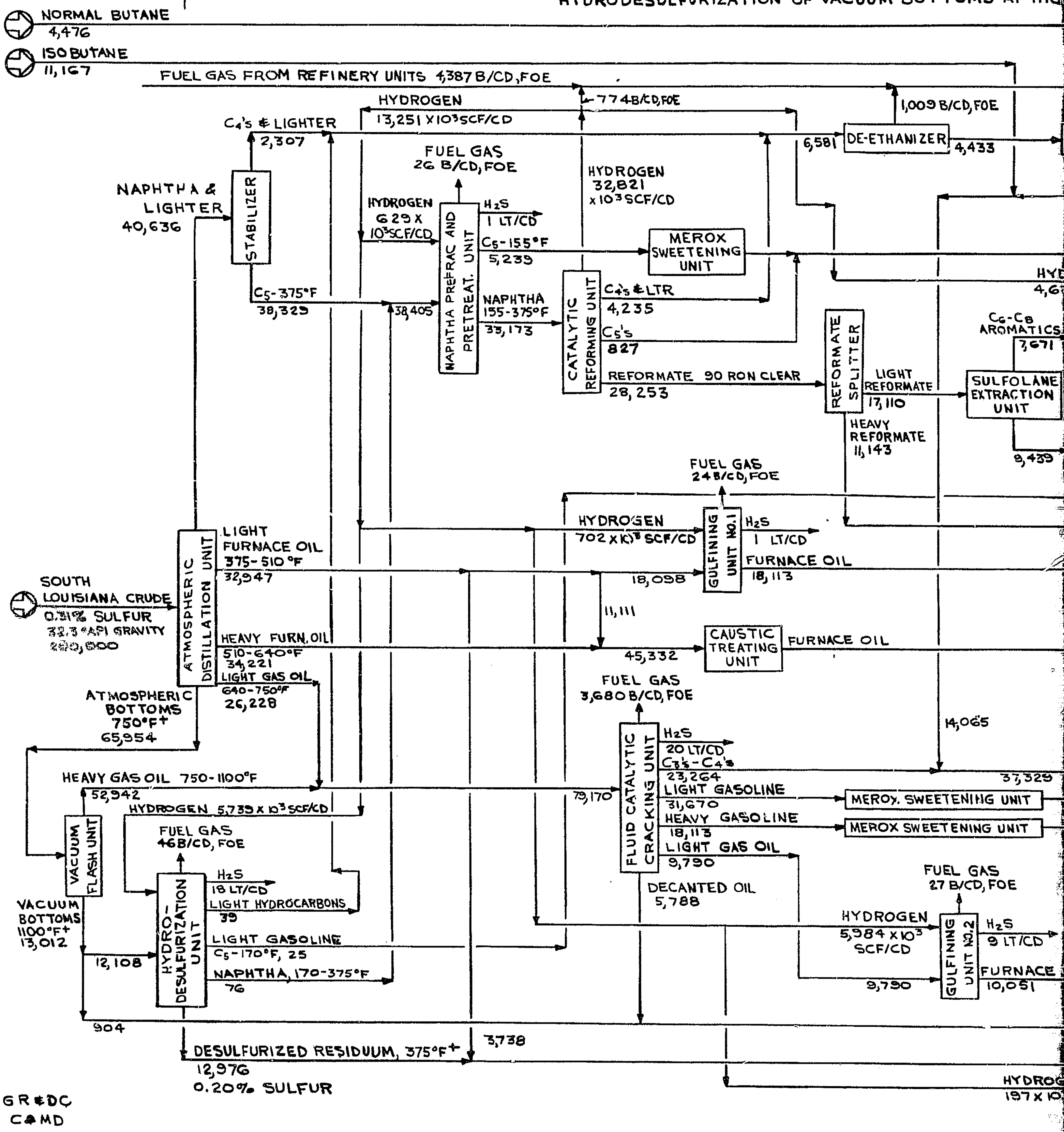
FIGURE III-8
REPRESENTIVE EXISTING REFINERY CHARGING LOW-SULFUR C
PRODUCTION OF GAS TURBINE FUEL - CASE 1.33
HYDRODESULFURIZATION OF VACUUM BOTTOMS AT HIG



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NOTE: ALL FLOW RATES IN B/CD EXCEPT AS OTHERWISE SHOWN.

FIGURE III-8
TIVE EXISTING REFINERY CHARGING LOW-SULFUR CRUDE OIL
PRODUCTION OF GAS TURBINE FUEL - CASE 1.33
DRODESULFURIZATION OF VACUUM BOTTOMS AT HIGH SEVERITY

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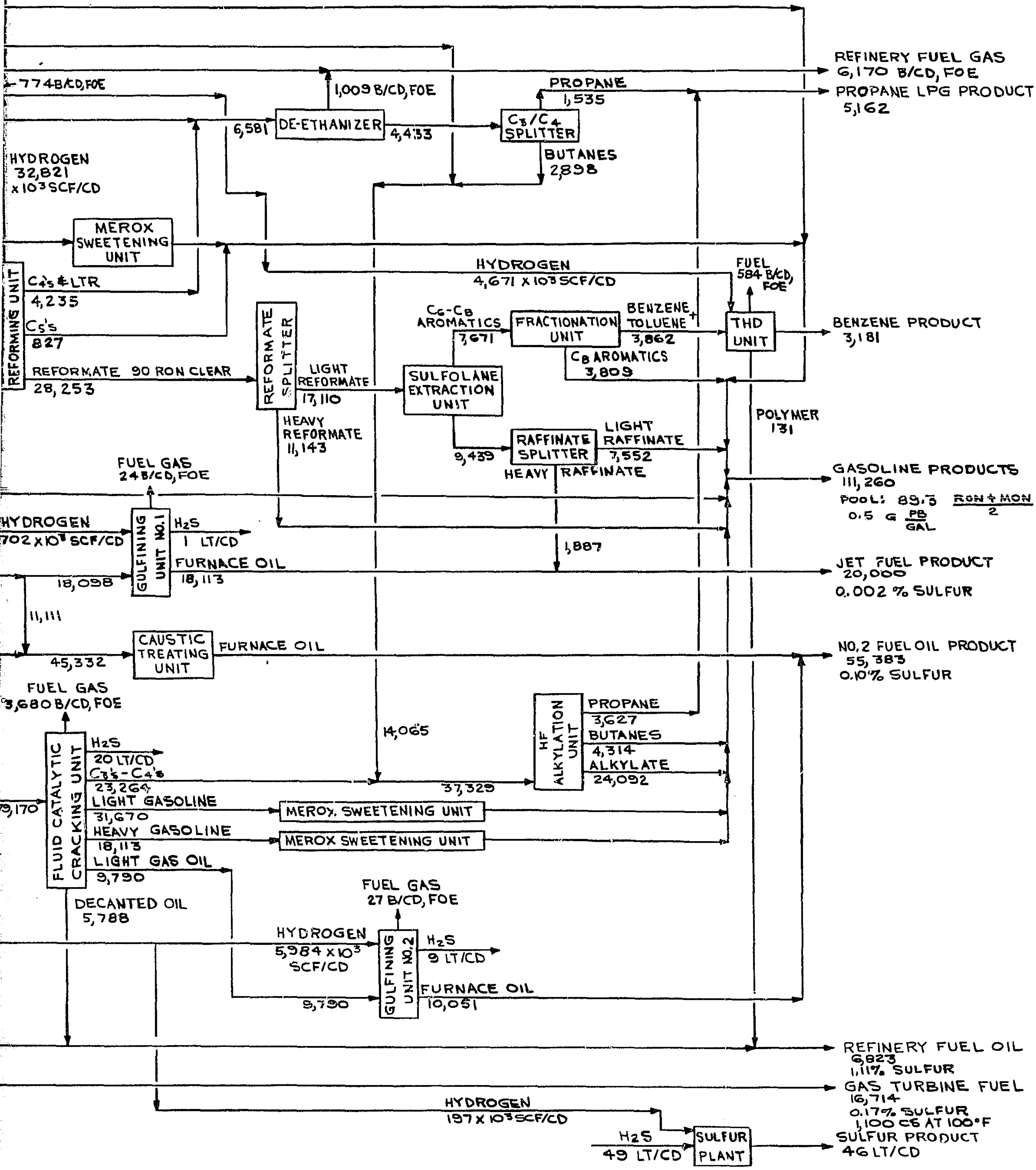

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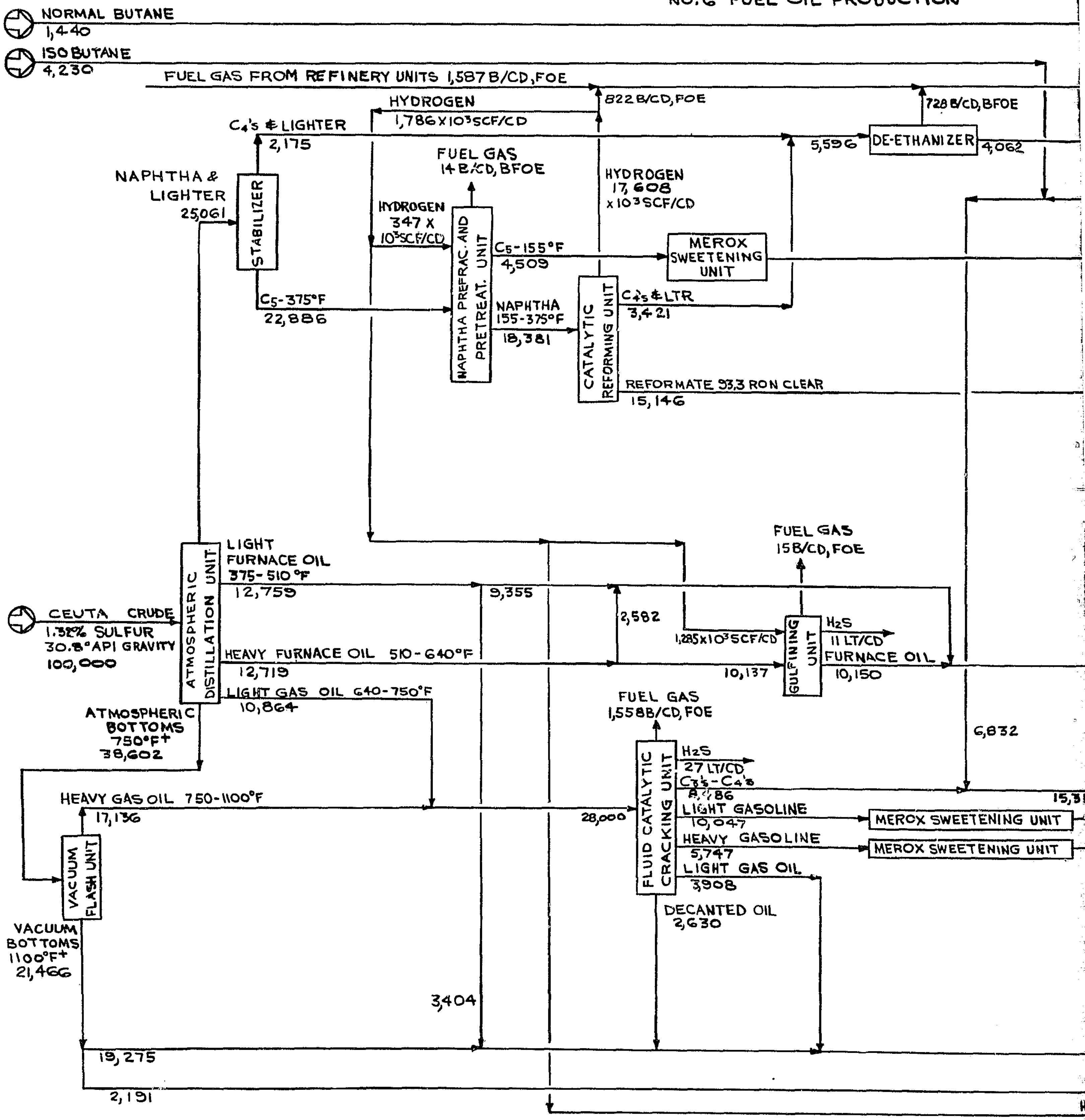
FIGURE III-3
REPRESENTIVE EXISTING REFINERY CHARGING HIGH-SULFUR
BASE CASE - CASE 2.00
NO. 6 FUEL OIL PRODUCTION



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NOTE: ALL FLOW RATES IN B/CD EXCEPT AS OTHERWISE SHOWN.

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FIGURE III-9
E EXISTING REFINERY CHARGING HIGH-SULFUR CRUDE OIL
BASE CASE - CASE 2.00
NO. 6 FUEL OIL PRODUCTION

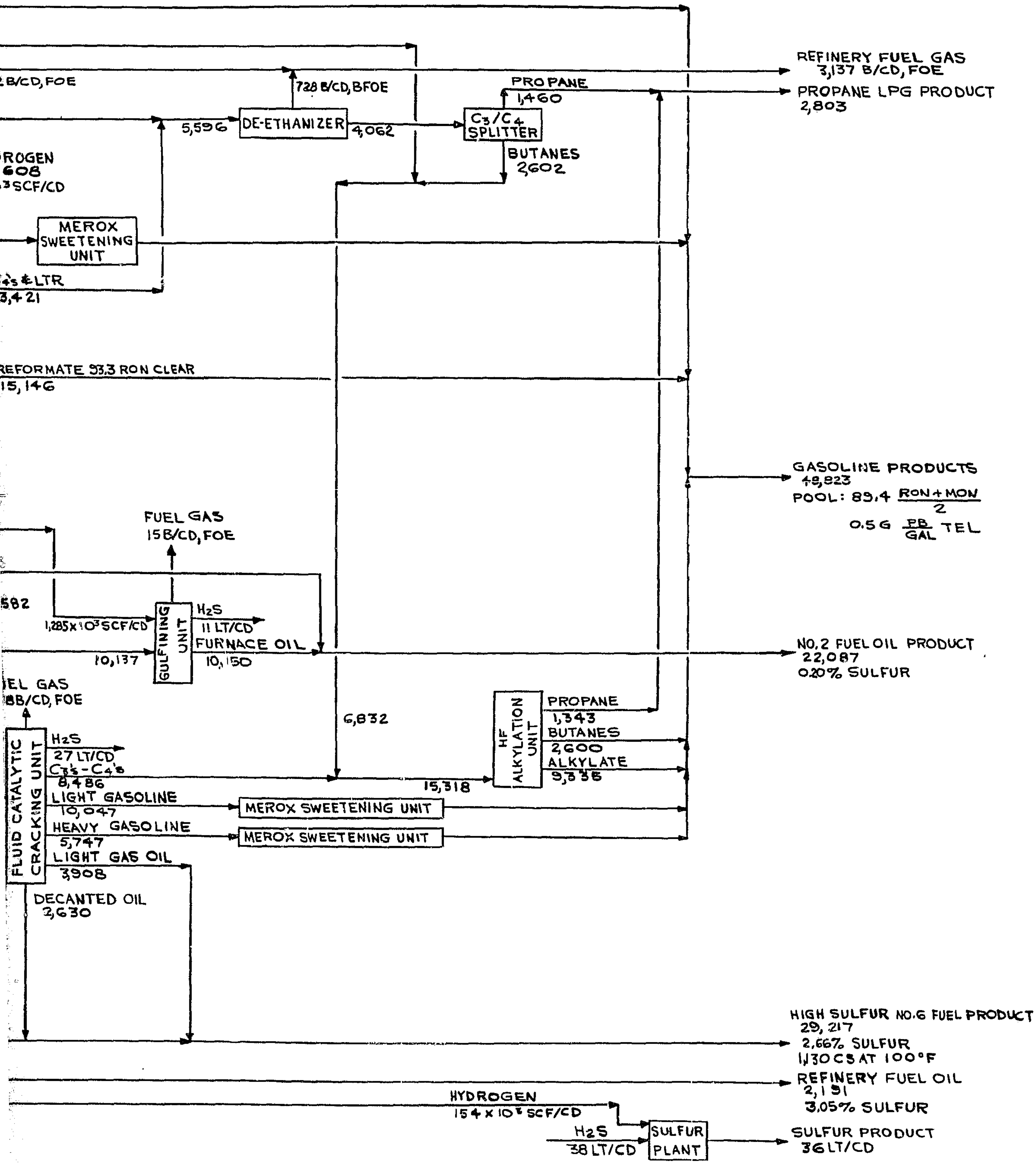
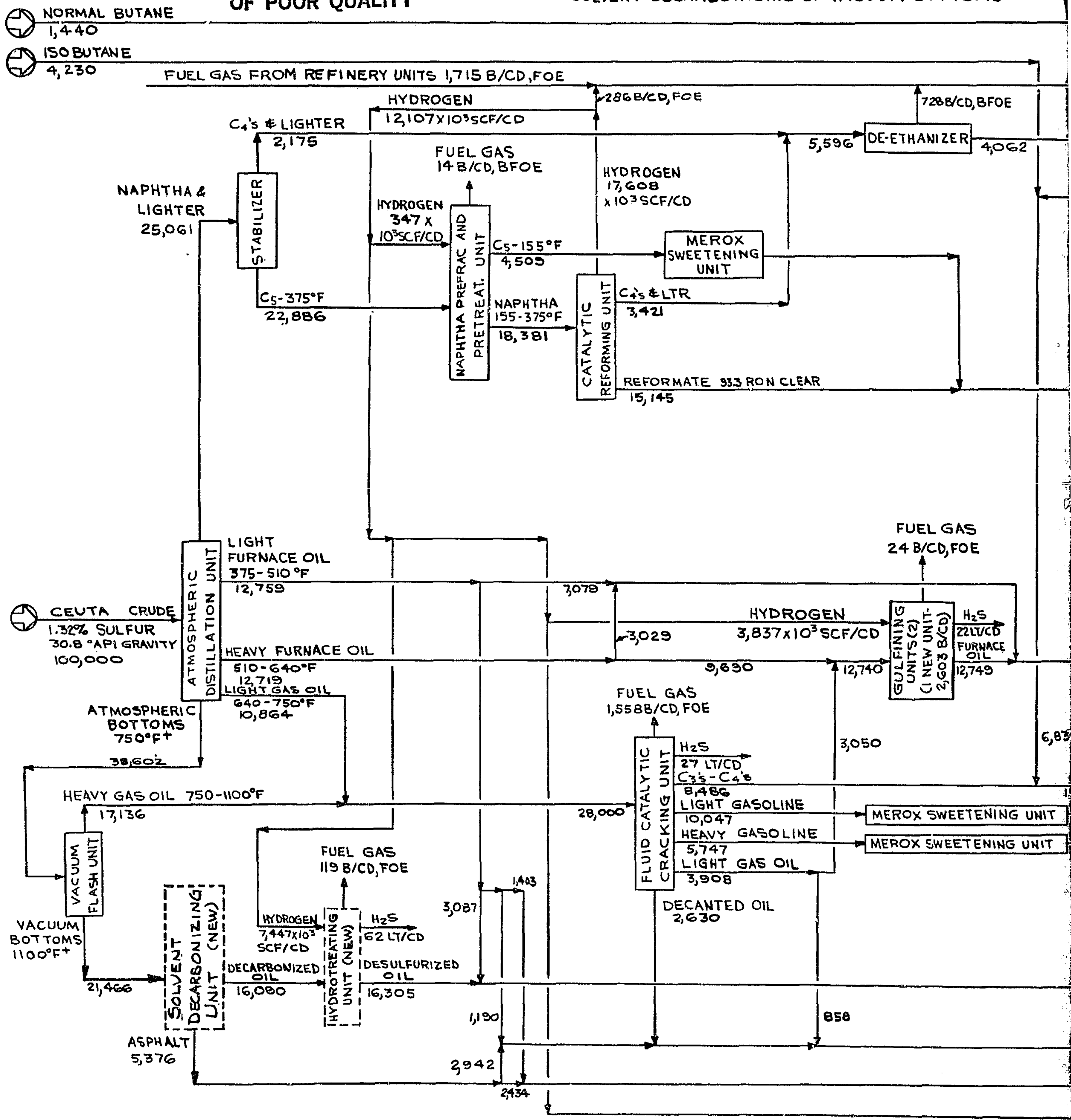


FIGURE III-10
REPRESENTIVE EXISTING REFINERY CHARGING HIGH SULFUR
PRODUCTION OF GAS TURBINE FUEL - CASE
SOLVENT DECARBONIZING OF VACUUM BOTTOMS



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NOTE: ALL FLOW RATES IN B/CD EXCEPT AS OTHERWISE SHOWN.

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FIGURE III-10
E EXISTING REFINERY CHARGING HIGH SULFUR CRUDE OIL
PRODUCTION OF GAS TURBINE FUEL - CASE 2,10
NT DECARBONIZING OF VACUUM BOTTOMS

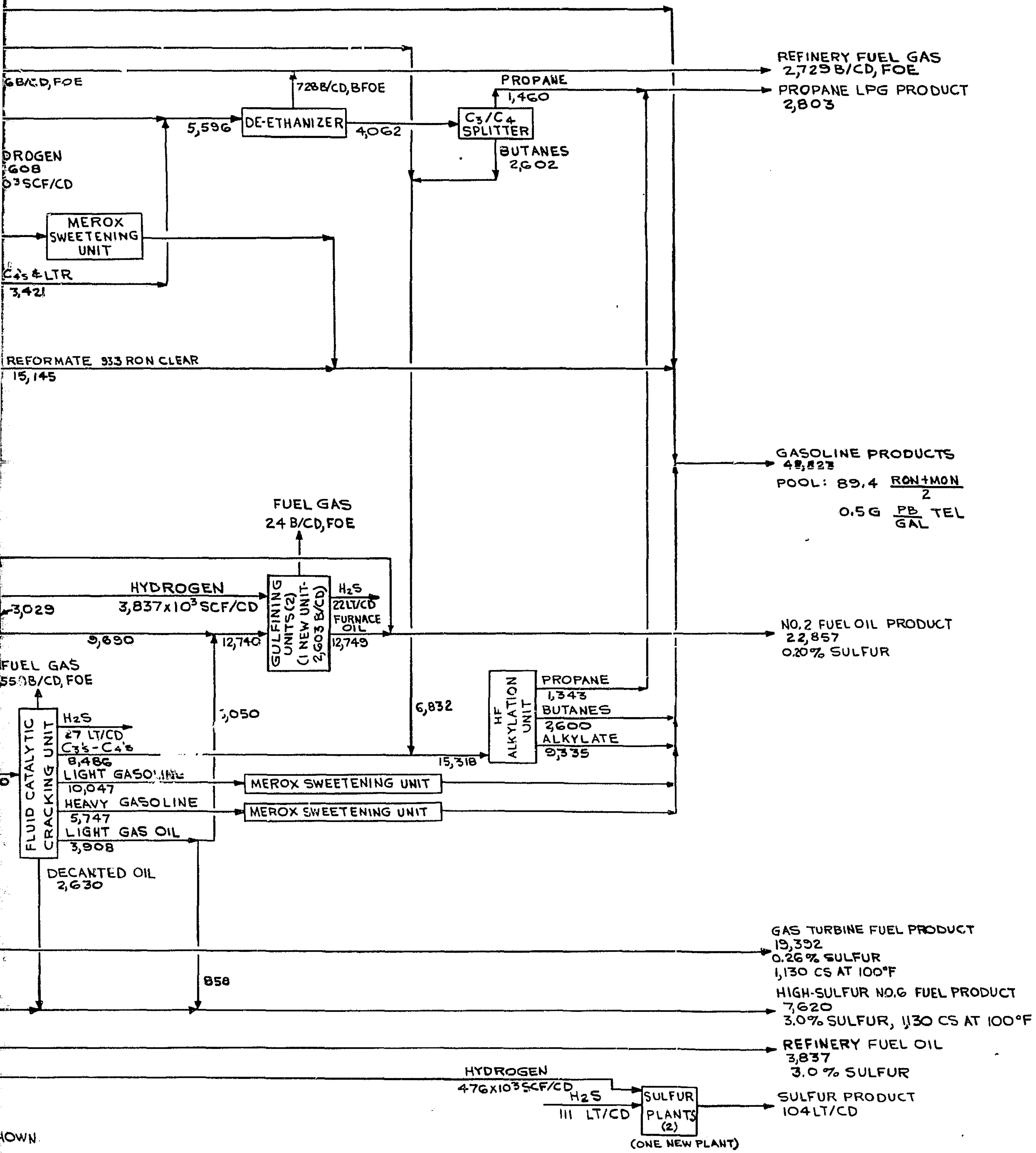

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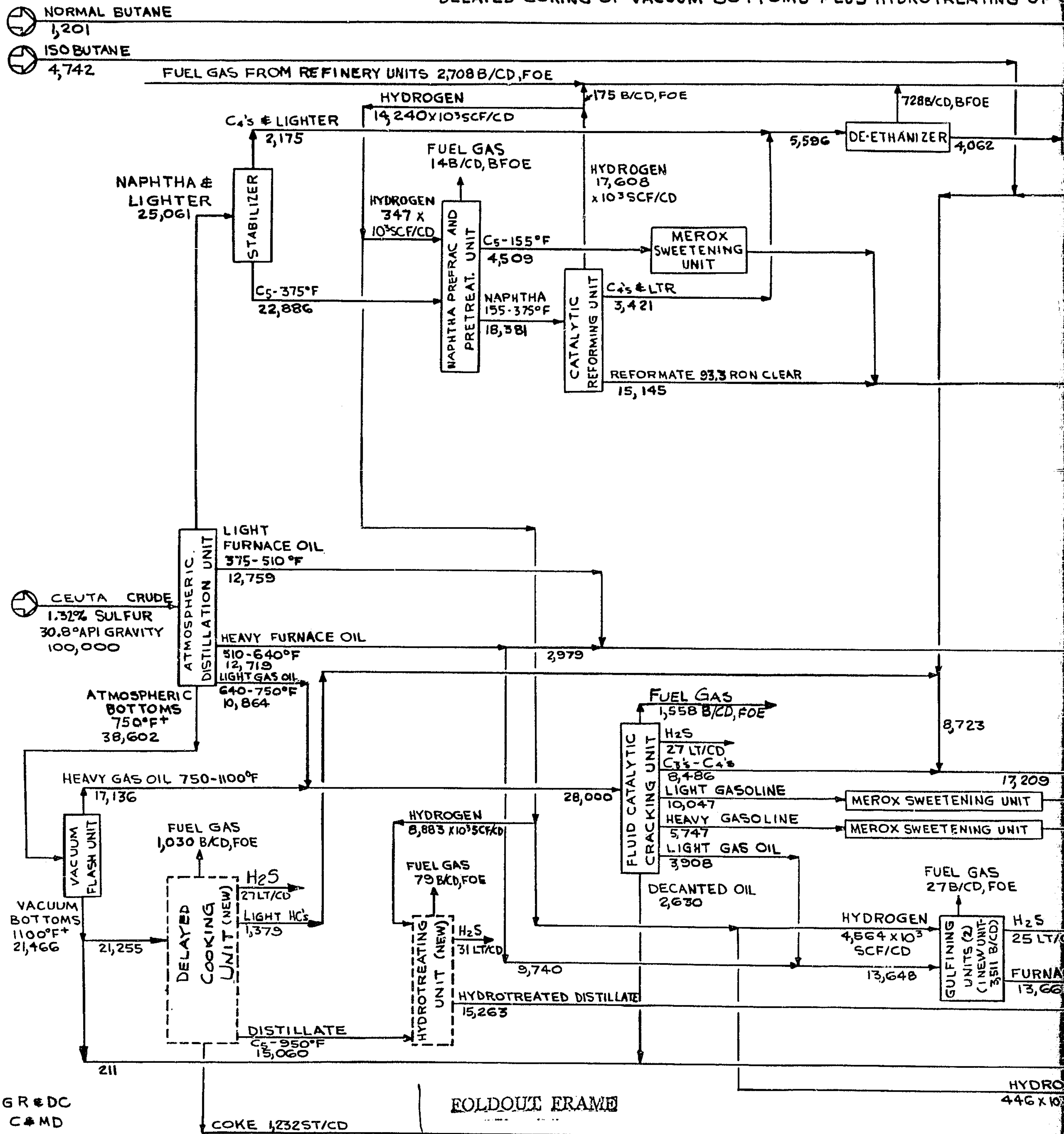
FIGURE III-11
REPRESENTIVE EXISTING REFINERY CHARGING HIGH-SULFUR
PRODUCTION OF GAS TURBINE FUEL – CASE 2.21
DELAYED COKING OF VACUUM BOTTOMS PLUS HYDROTREATING OF



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NOTE: ALL FLOW RATES IN B/CD EXCEPT AS OTHERWISE SHOWN

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FIGURE III- 11

EXISTING REFINERY CHARGING HIGH-SULFUR CRUDE OIL

ON OF GAS TURBINE FUEL - CASE 2.21

VACUUM BOTTOMS PLUS HYDROTREATING OF C_5-950°F COKER DISTILLATE

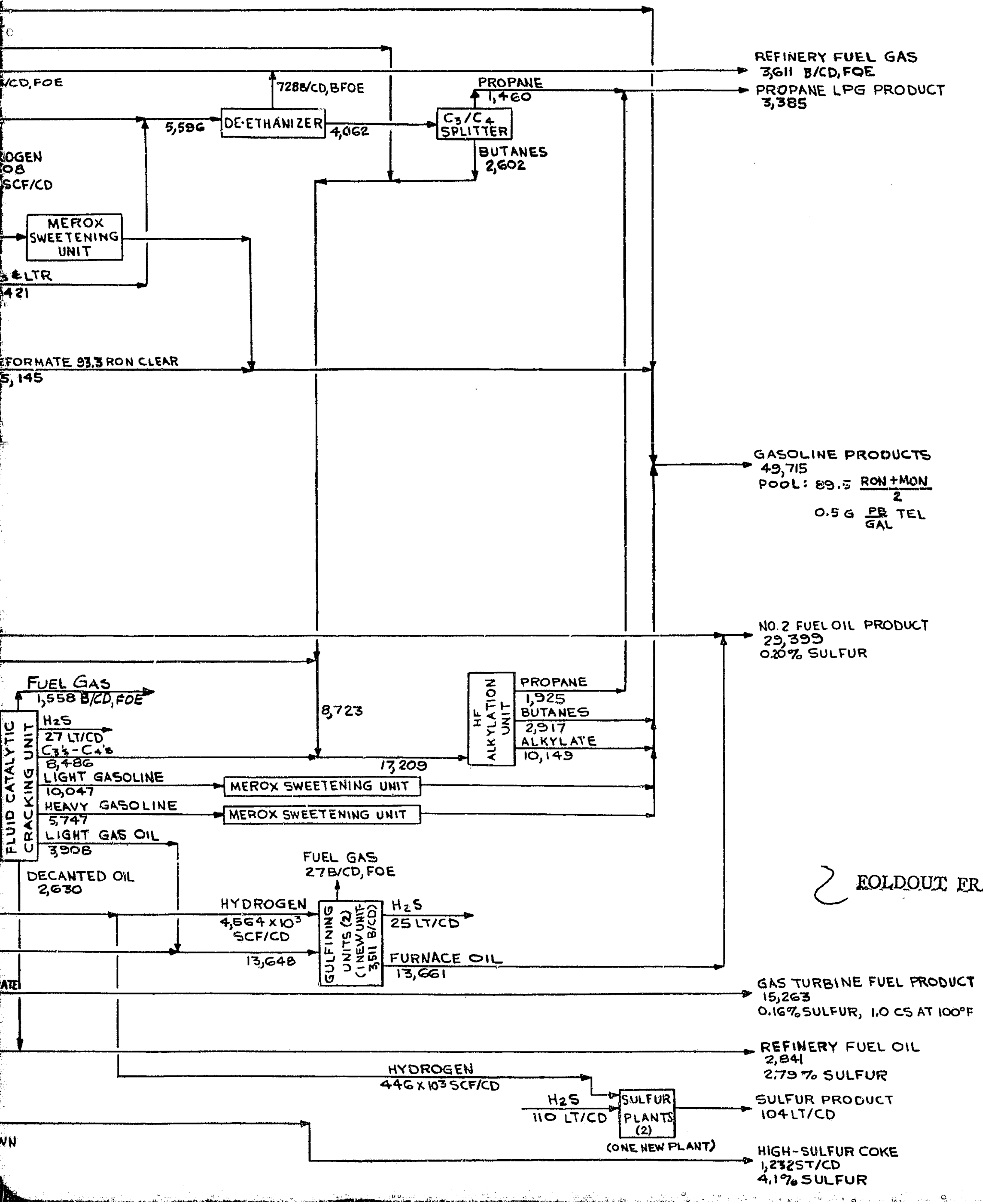

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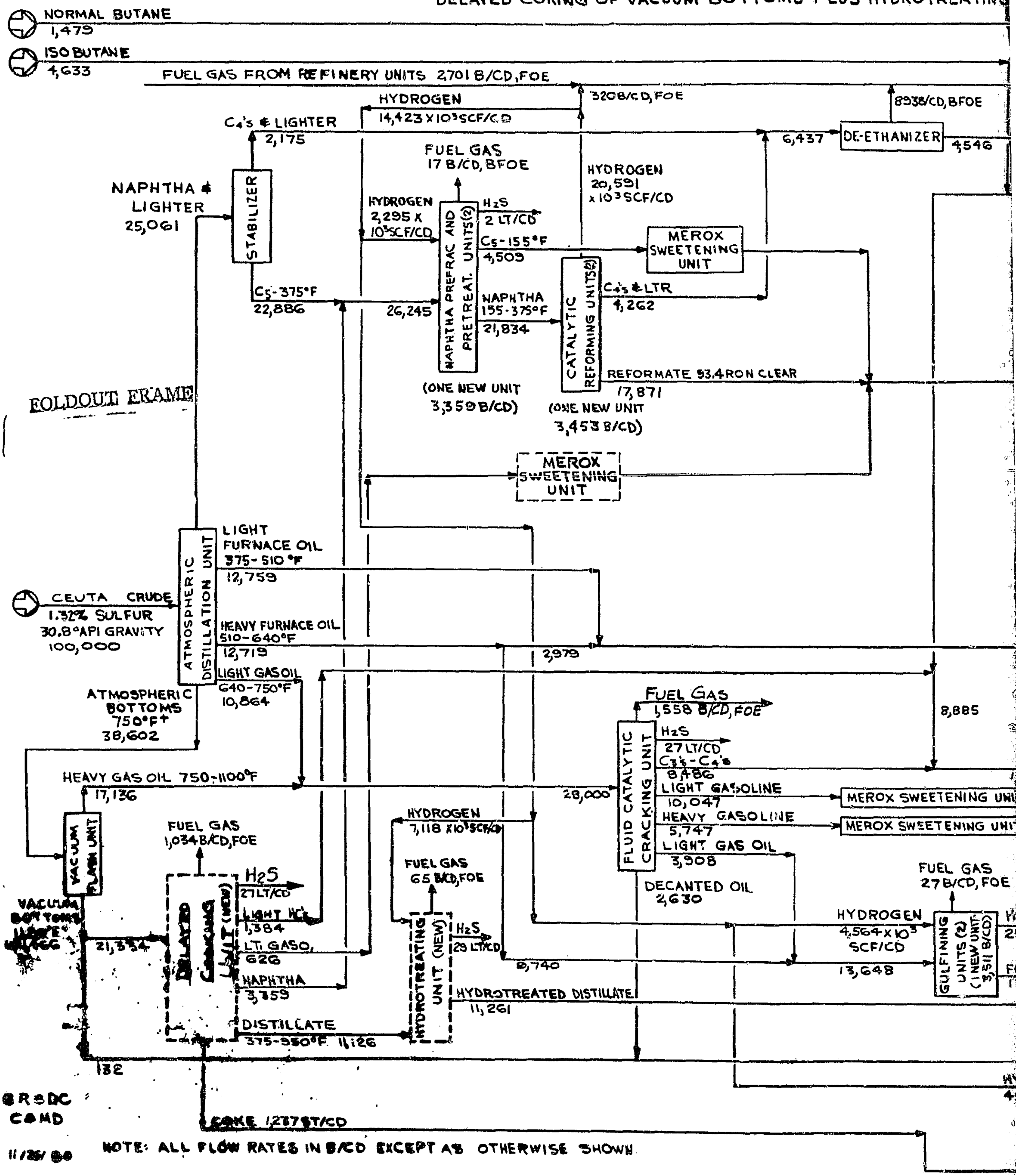
FIGURE III-12
REPRESENTIVE EXISTING REFINERY CHARGING HIGH-SUL
PRODUCTION OF GAS TURBINE FUEL - CASE 2.22
DELAYED COKING OF VACUUM BOTTOMS PLUS HYDROTREATING



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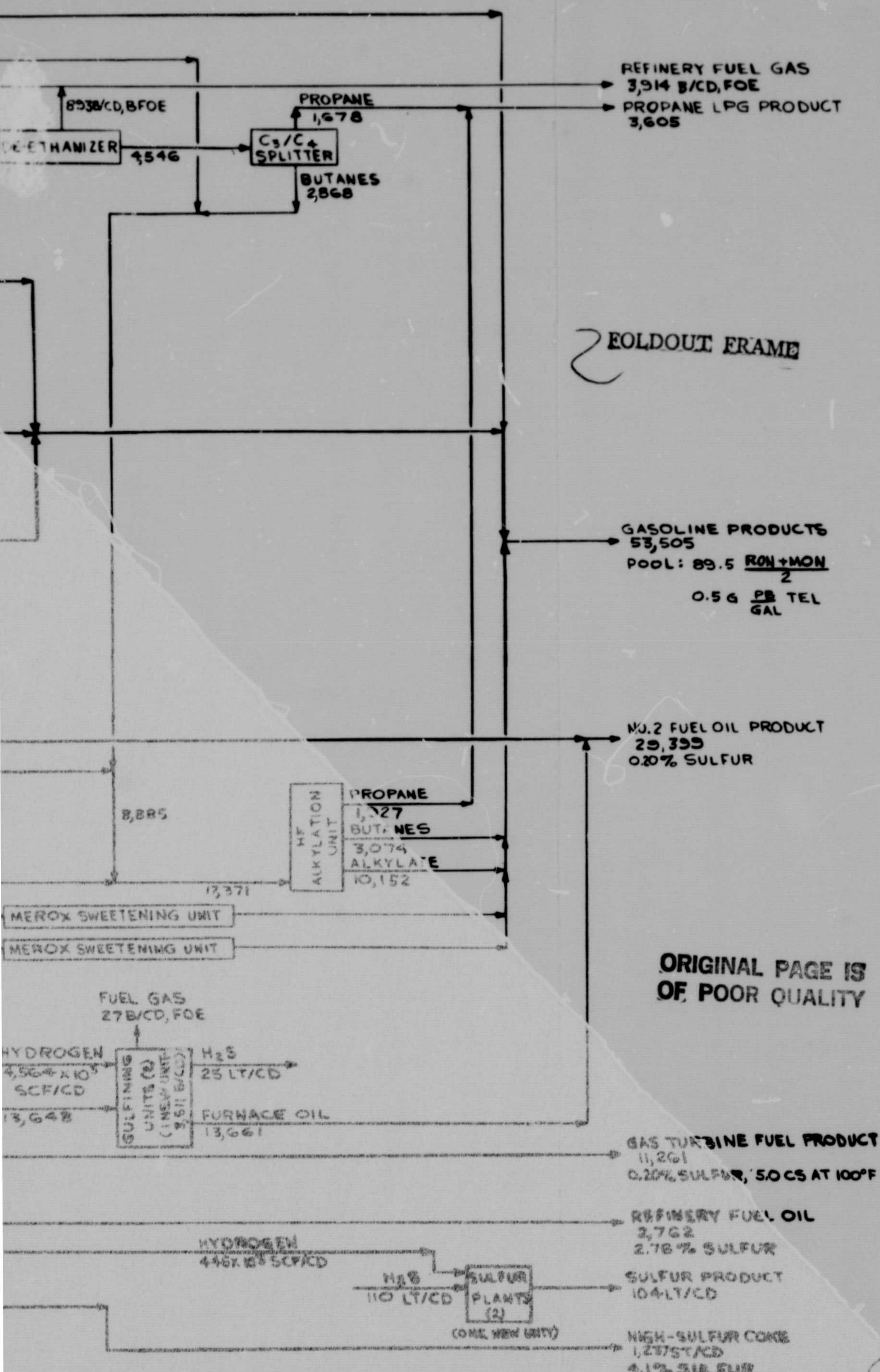
NOTE: ALL FLOW RATES IN B/CD EXCEPT AS OTHERWISE SHOWN

-12
RGING HIGH-SULFUR CRUDE OIL
EL - CASE 2.22
US HYDROTREATING OF 375-950°F COKER DISTILLATE



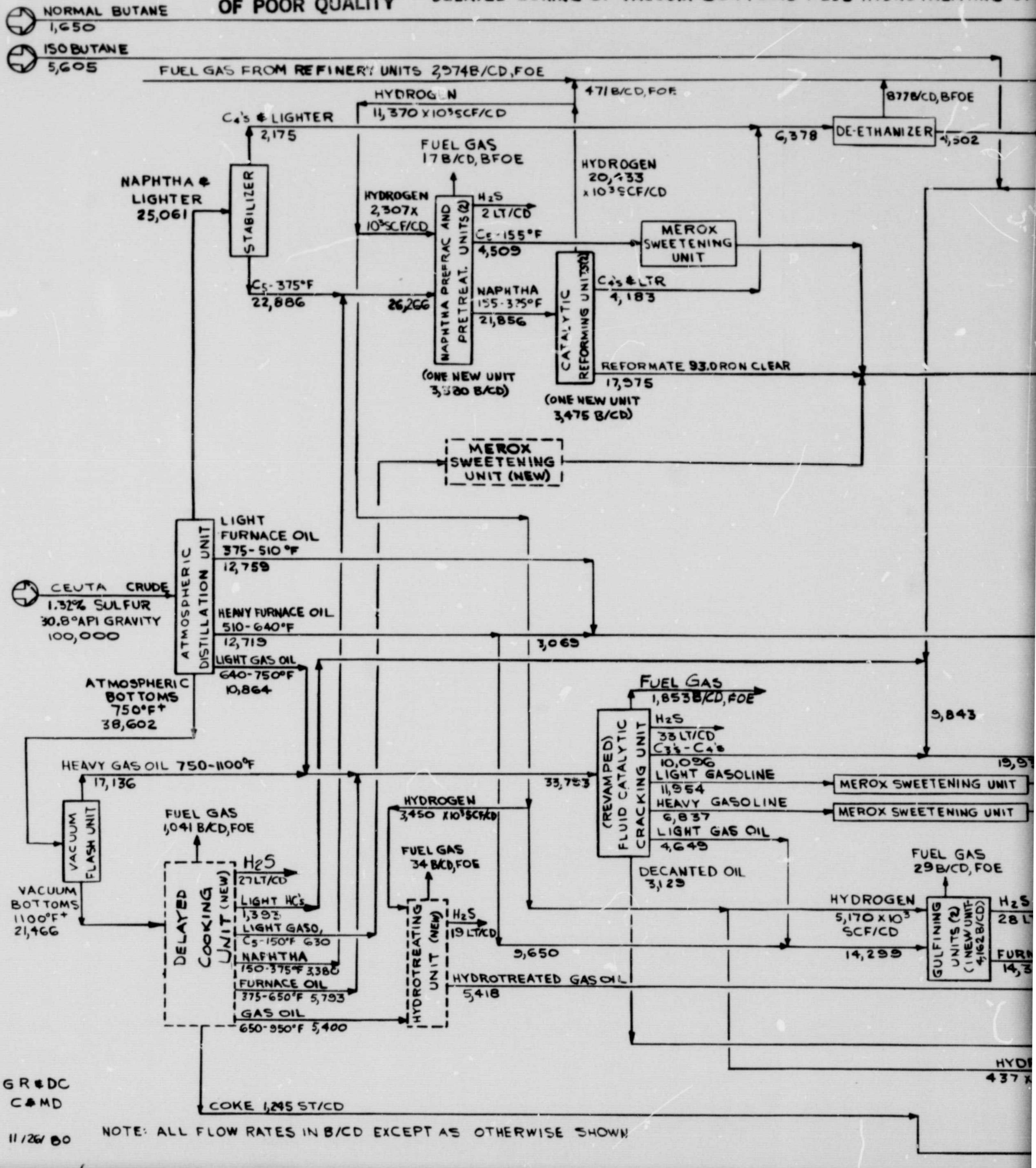
C-2

FIGURE III-13

REPRESENTIVE EXISTING REFINERY CHARGING HIGH-SULFUR

PRODUCTION OF GAS TURBINE FUEL - CASE 2.23

DELAYED COKING OF VACUUM BOTTOMS PLUS HYDROTREATING OF



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NOTE: ALL FLOW RATES IN B/CD EXCEPT AS OTHERWISE SHOWN

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FIGURE III - 13
REFINERY CHARGING HIGH-SULFUR CRUDE OIL
TURBINE FUEL - CASE 2.23
OTTOMS PLUS HYDROTREATING OF 650-950 °F COKER GAS OIL

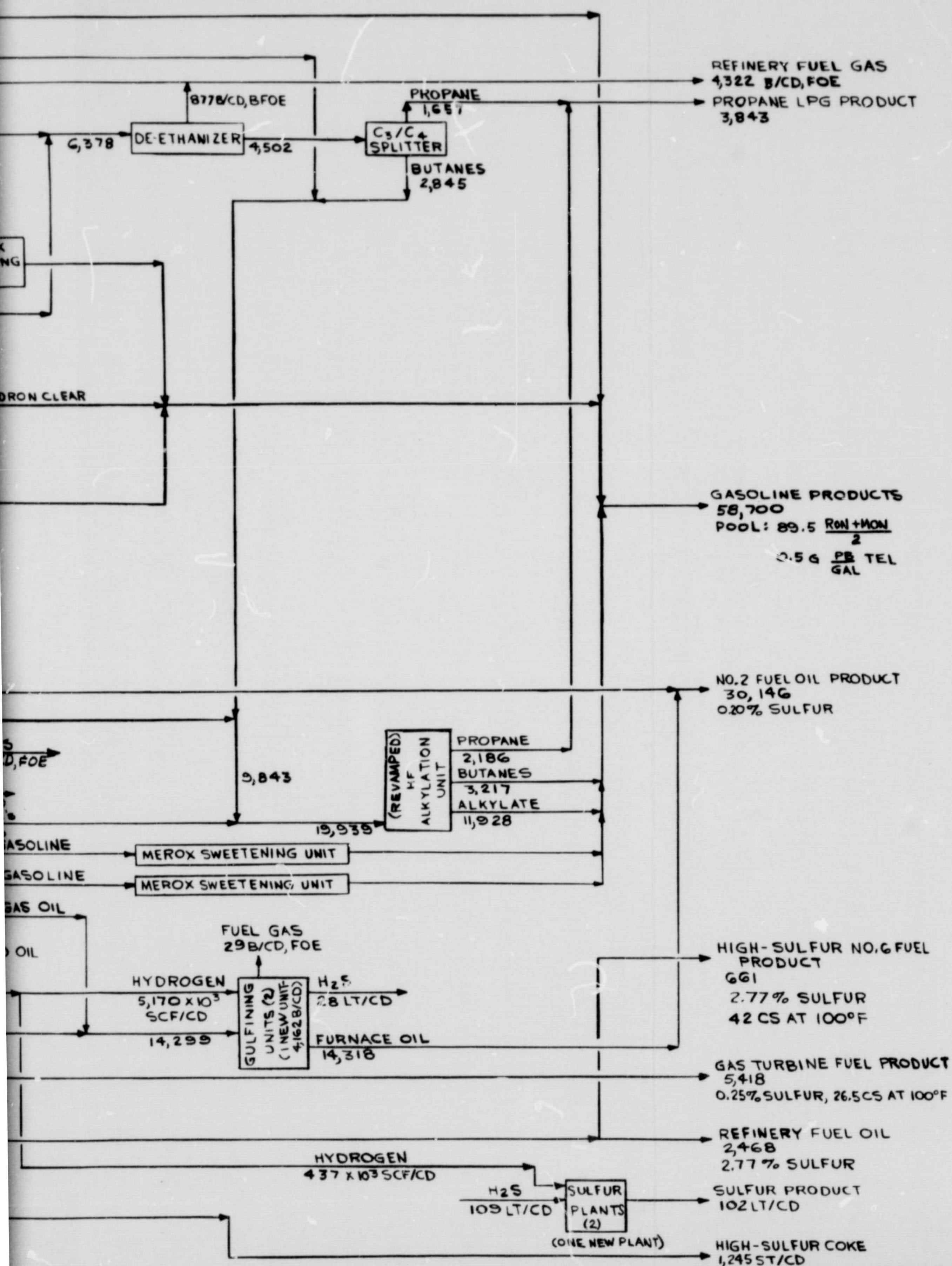

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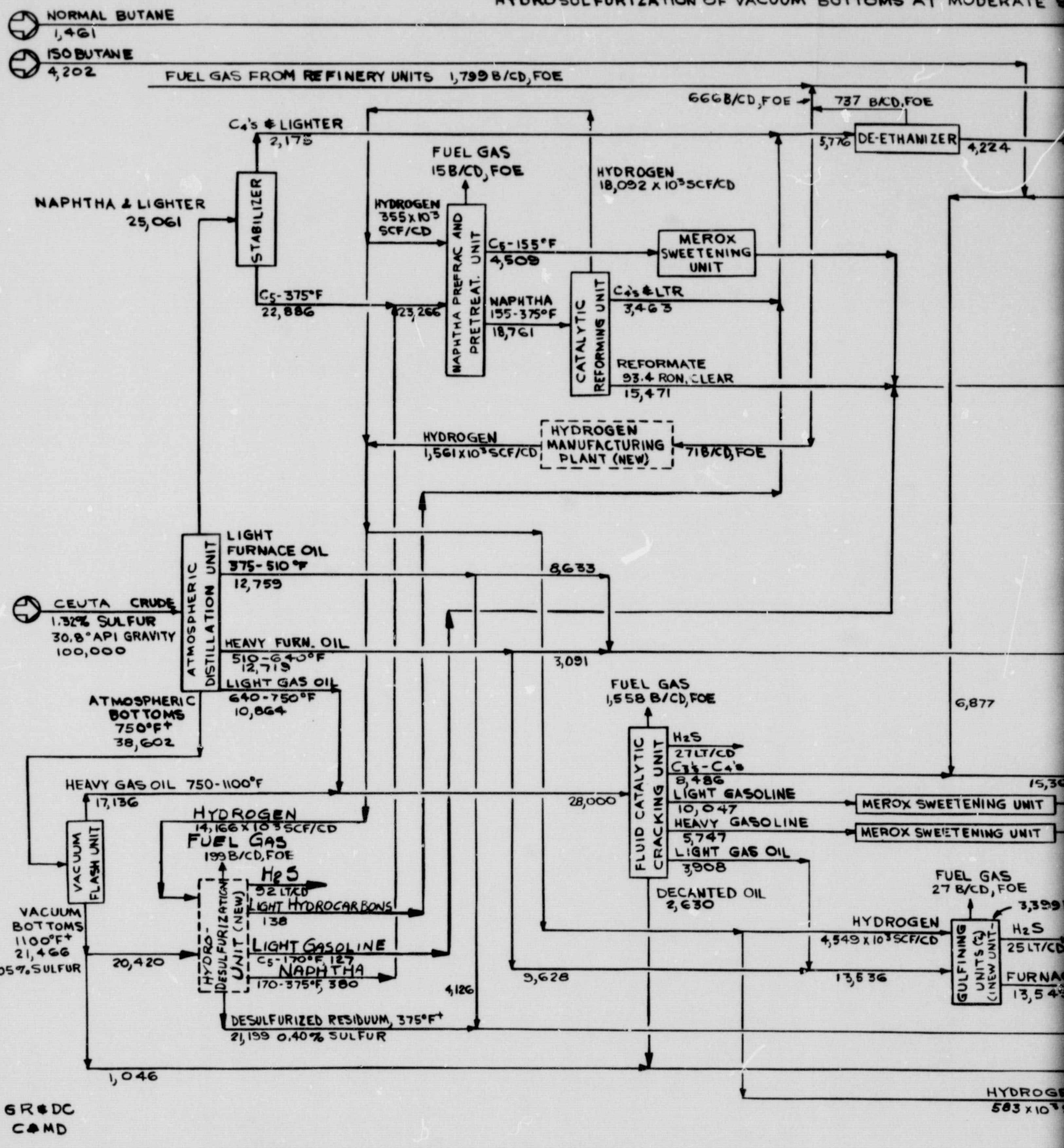
FIGURE III-14
REPRESENTIVE EXISTING REFINERY CHARGING HIGH-SULFUR
PRODUCTION OF GAS TURBINE FUEL - CASE 2.31
HYDROSULFURIZATION OF VACUUM BOTTOMS AT MODERATE



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NOTE: ALL FLOW RATES IN B/CD EXCEPT AS OTHERWISE SHOWN.

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IGURE III-14
ERY CHARGING HIGH-SULFUR CRUDE OIL
S TURBINE FUEL - CASE 2.31
UM BOTTOMS AT MODERATE SEVERITY

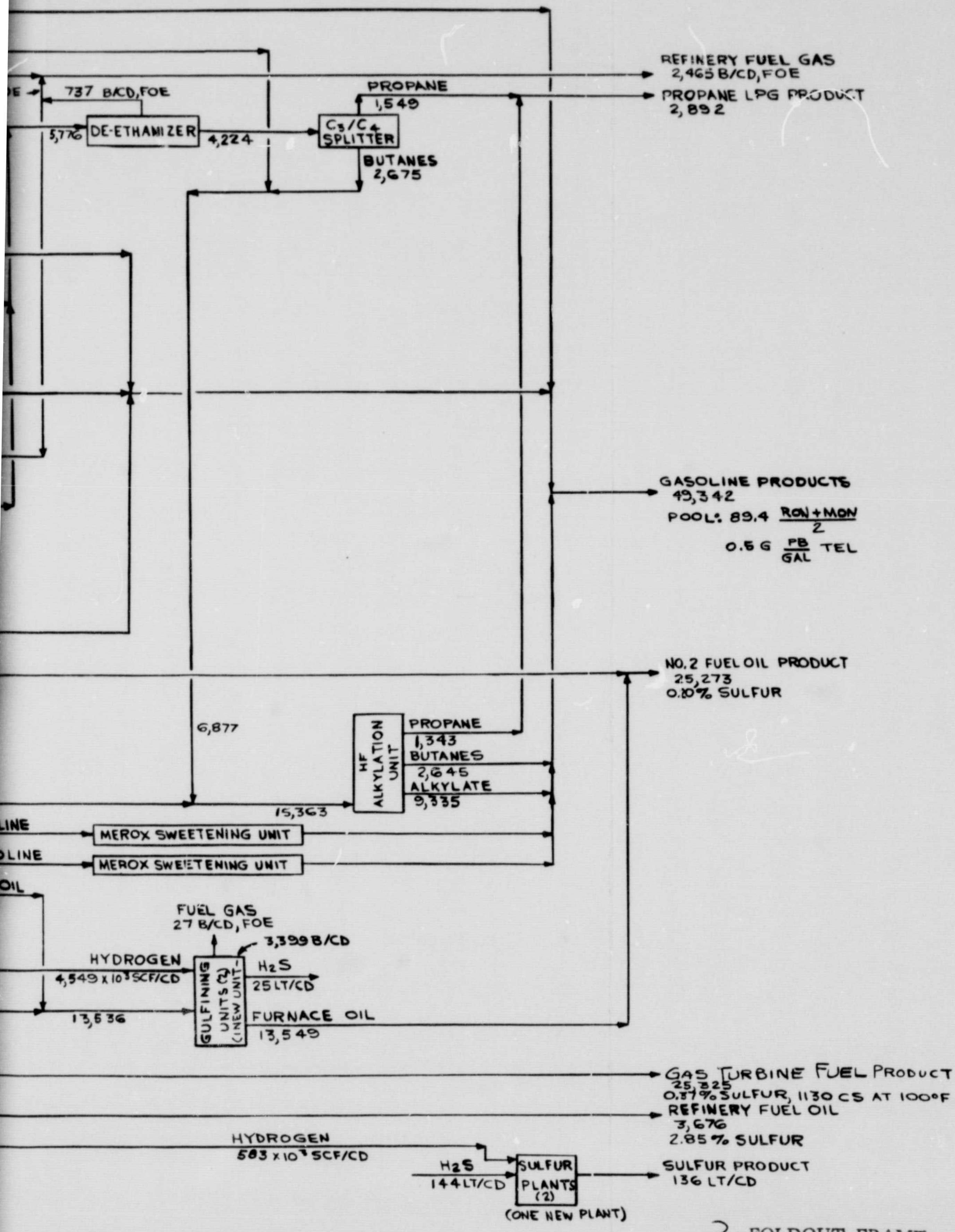

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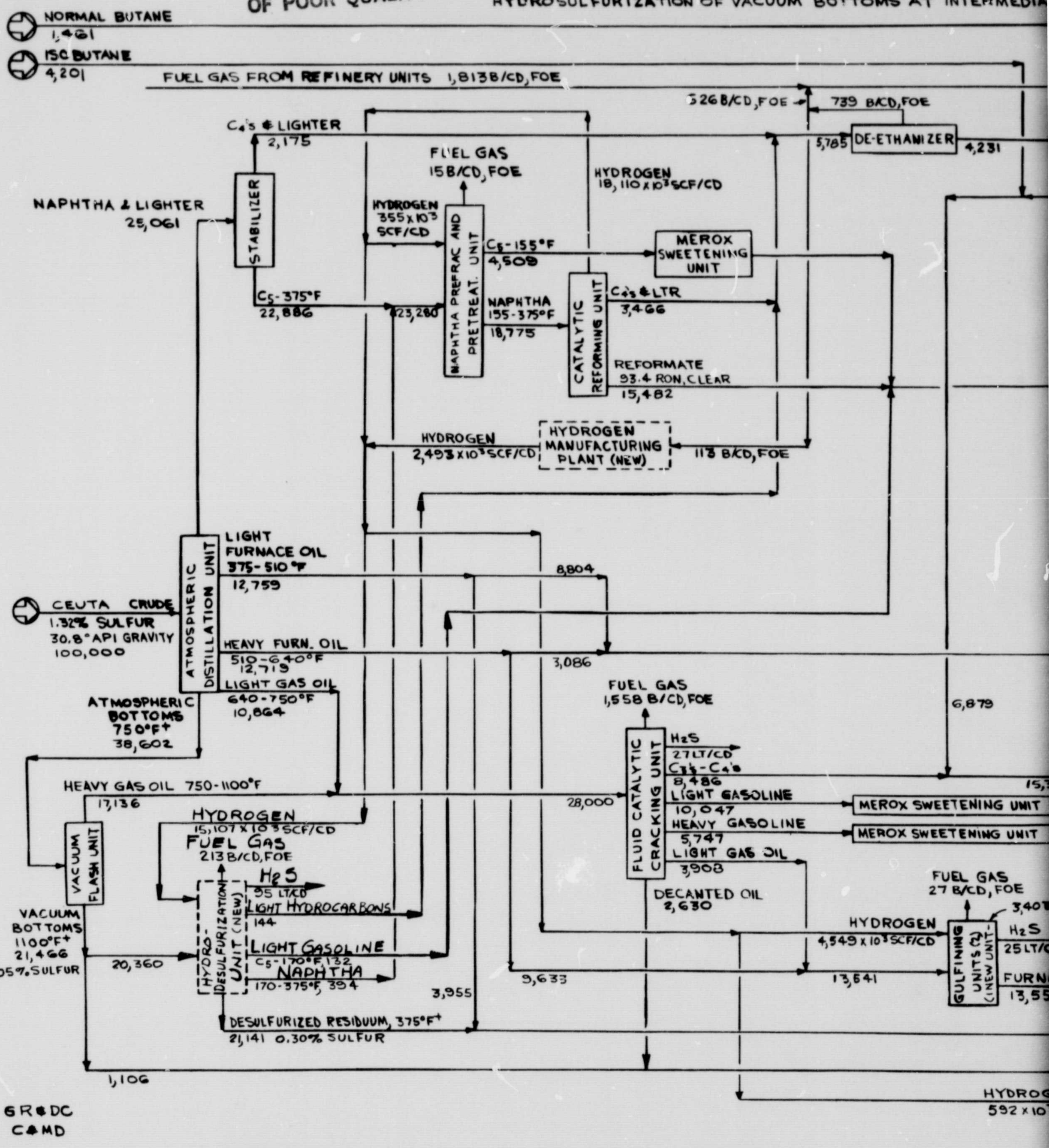
FIGURE III-15
REPRESENTIVE EXISTING REFINERY CHARGING HIGH-SULFUR
PRODUCTION OF GAS TURBINE FUEL- CASE 2.3
HYDROSULFURIZATION OF VACUUM BOTTOMS AT INTERMEDIA



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NOTE: ALL FLOW RATES IN B/CD EXCEPT AS OTHERWISE SHOWN.

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FIGURE III-15
REFINERY CHARGING HIGH-SULFUR CRUDE OIL
F GAS TURBINE FUEL - CASE 2.32
VACUUM BOTTOMS AT INTERMEDIATE SEVERITY

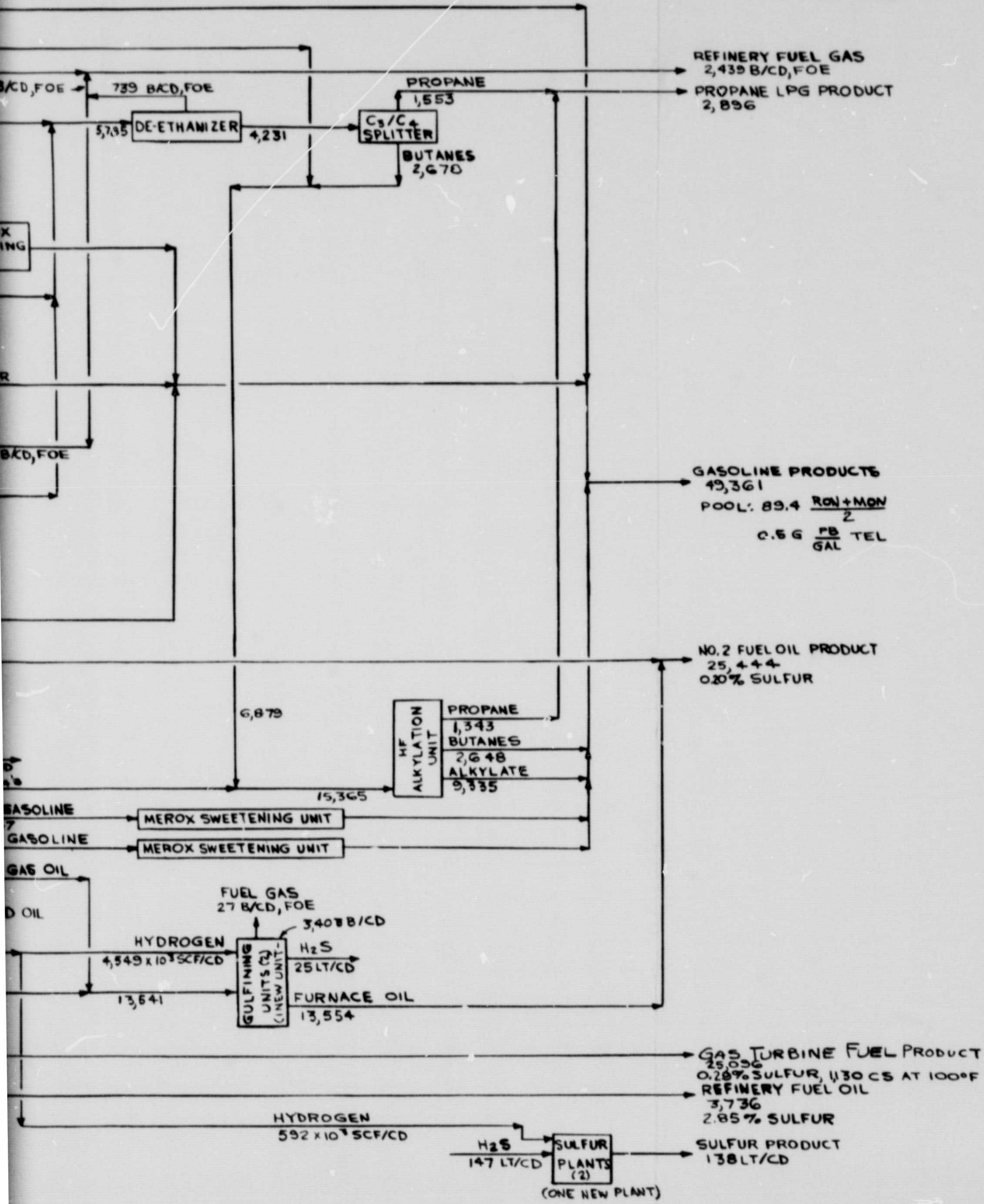

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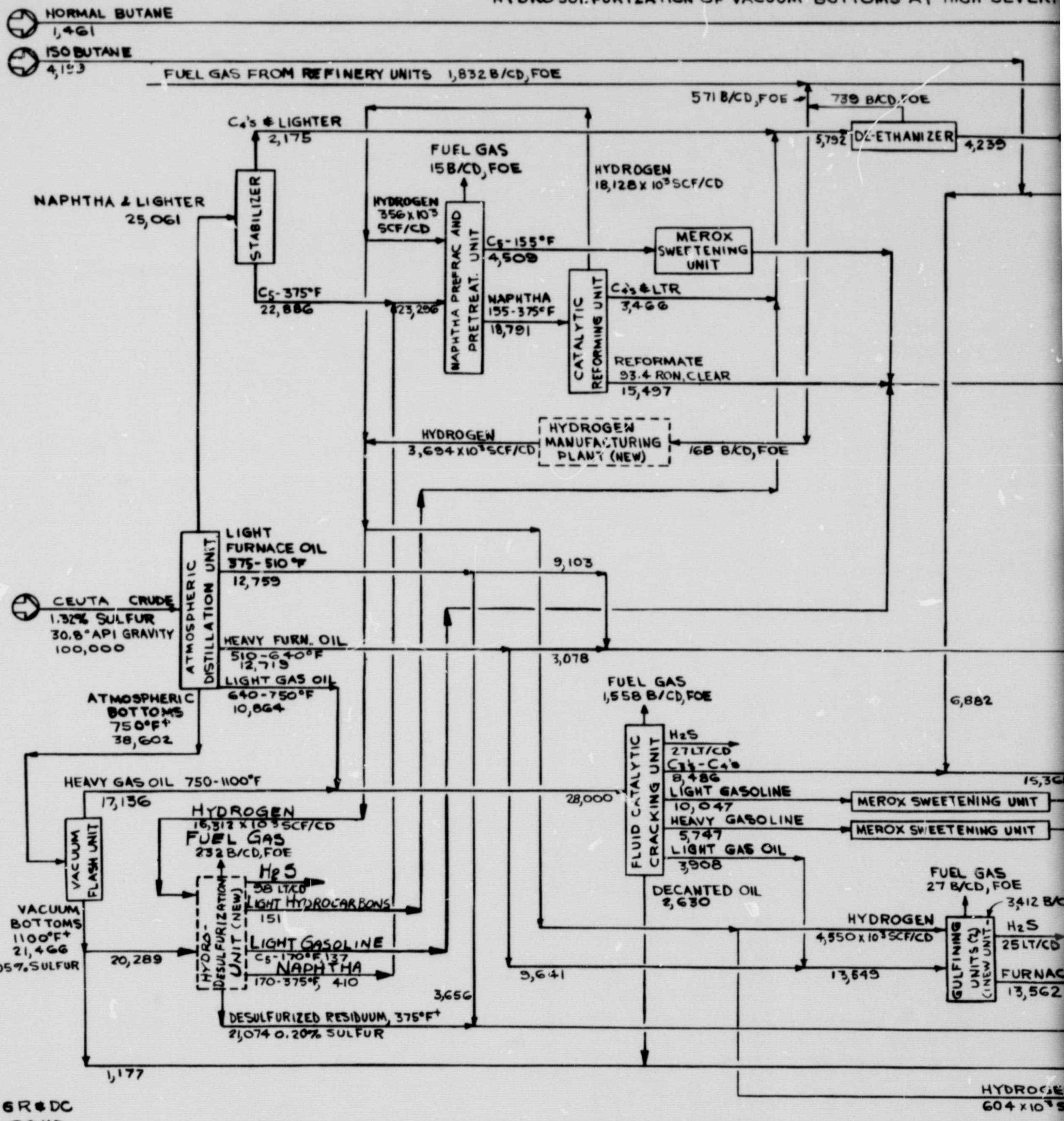
FIGURE III-16
REPRESENTIVE EXISTING REFINERY CHARGING HIGH-SULFUR
PRODUCTION OF GAS TURBINE FUEL- CASE 2.33
HYDROSULFURIZATION OF VACUUM BOTTOMS AT HIGH SEVERI



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NOTE: ALL FLOW RATES IN B/CD EXCEPT AS OTHERWISE SHOWN.

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FIGURE III-16
REFINERY CHARGING HIGH-SULFUR CRUDE OIL
OF GAS TURBINE FUEL - CASE 2.33
VACUUM BOTTOMS AT HIGH SEVERITY

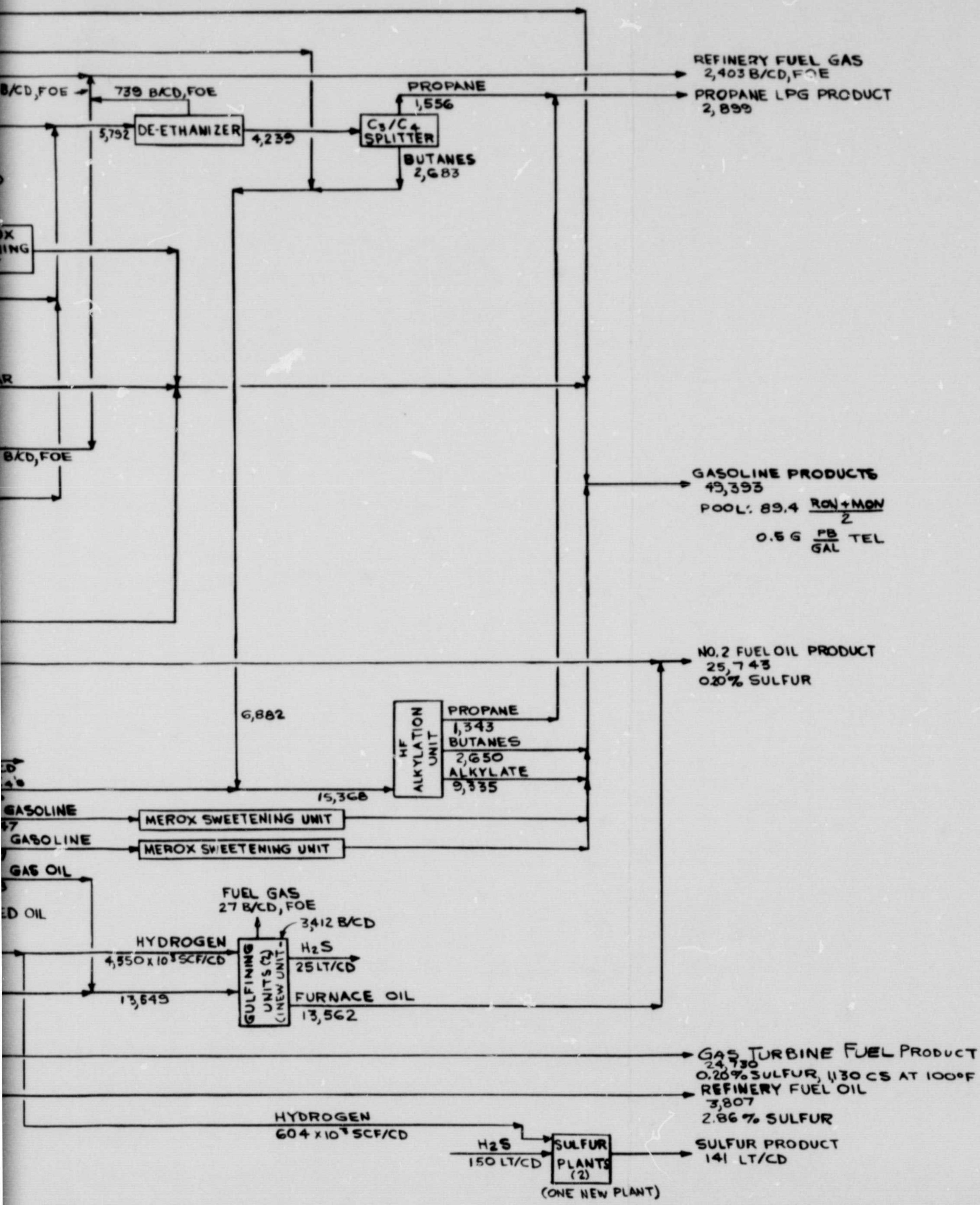
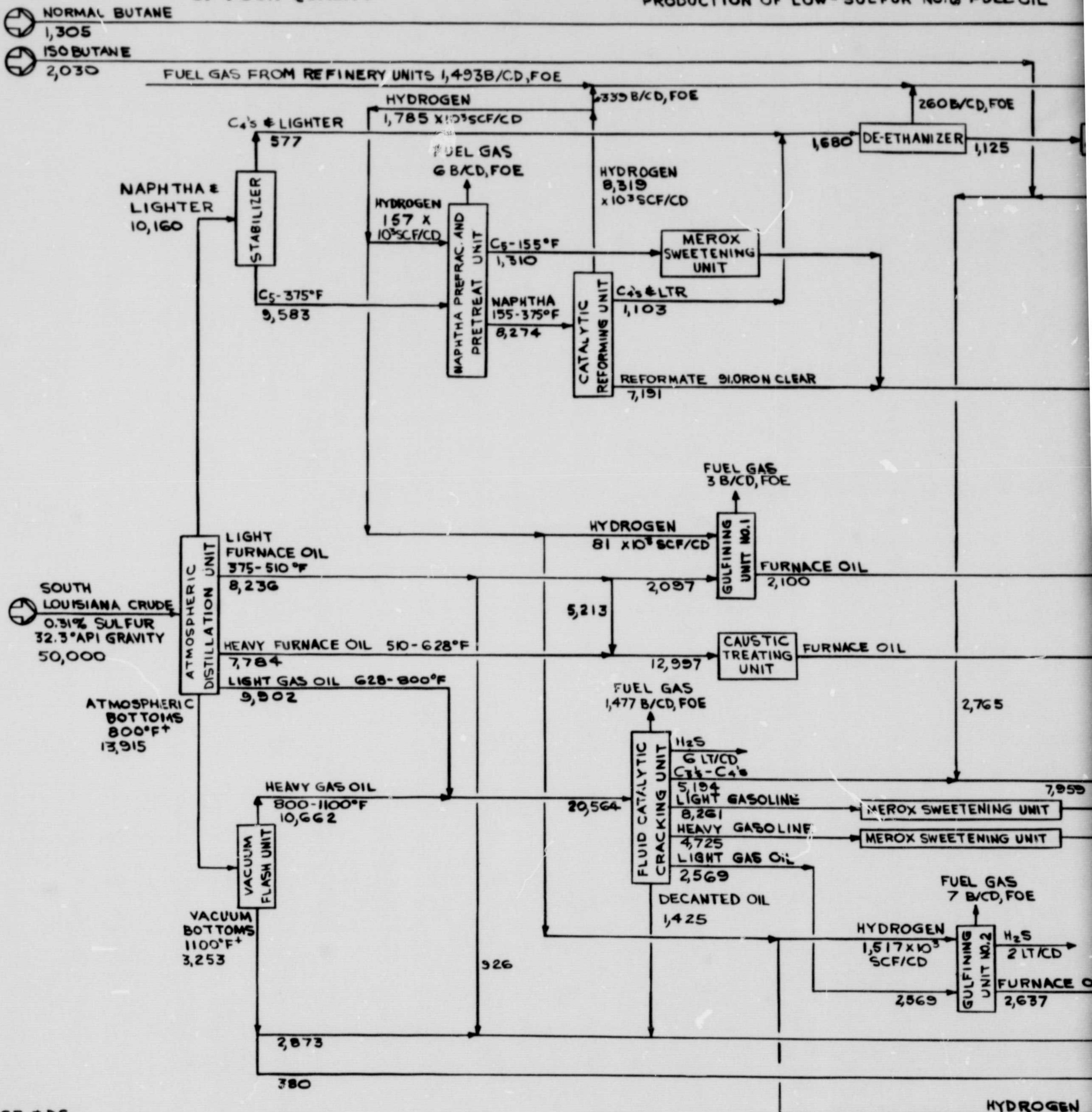


FIGURE III-17
REPRESENTATIVE EXISTING REFINERY CHARGING LOW-SULFUR C
BASE CASE - CASE 300
PRODUCTION OF LOW-SULFUR NO.6 FUEL OIL



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NOTE: ALL FLOW RATES IN B/CD EXCEPT AS OTHERWISE SHOWN.

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FIGURE III-17
STING REFINERY CHARGING LOW-SULFUR CRUDE OIL
BASE CASE - CASE 300
DUCTION OF LOW-SULFUR NO.6 FUEL OIL

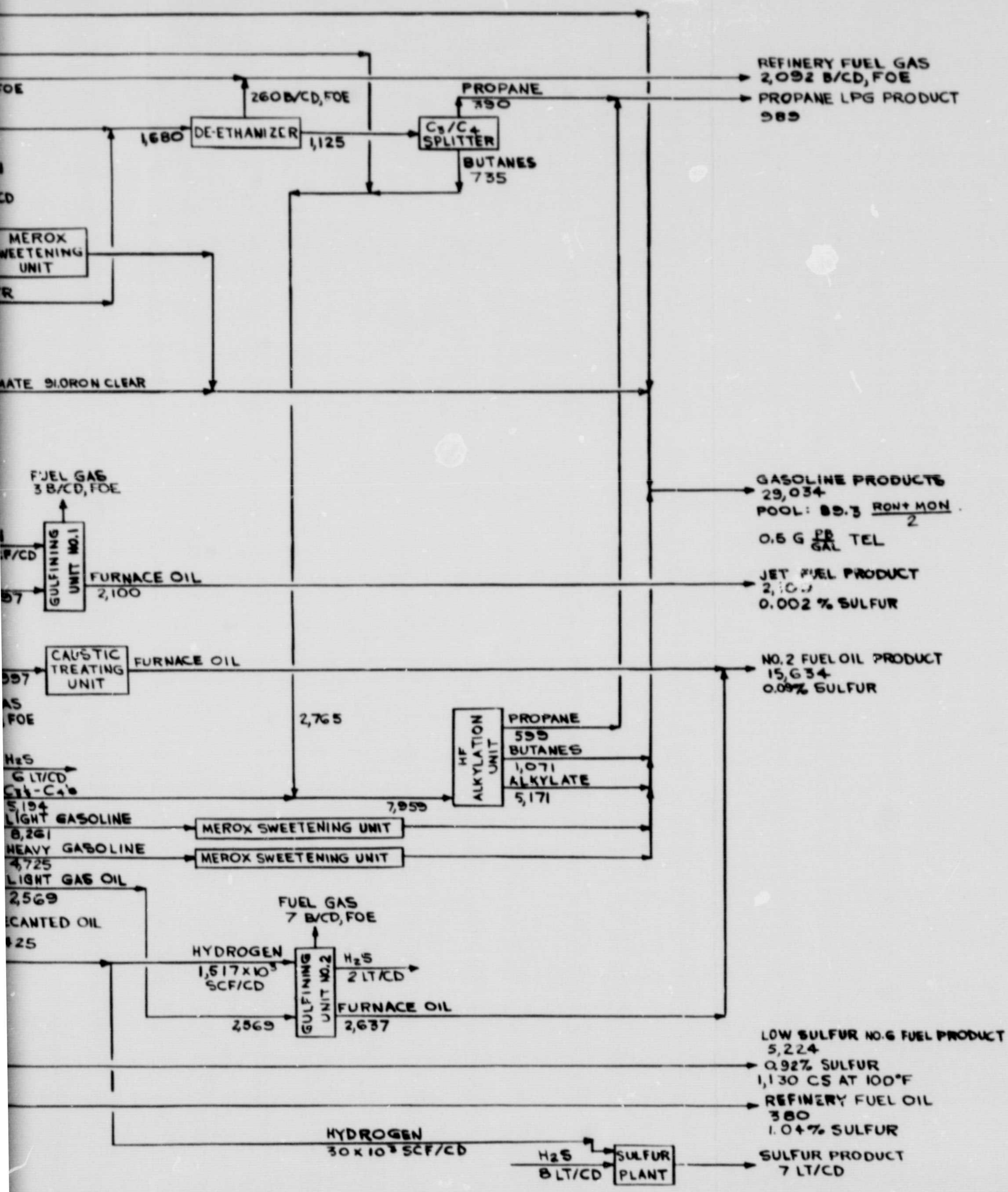

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FIGURE III-18
REPRESENTATIVE EXISTING REFINERY CHARGING SURFAC
GAS TURBINE FUEL PRODUCTION - CASE
SEVERE HYDROTREATING OF RAW SHALE OIL PLUS FLUID CATALYT

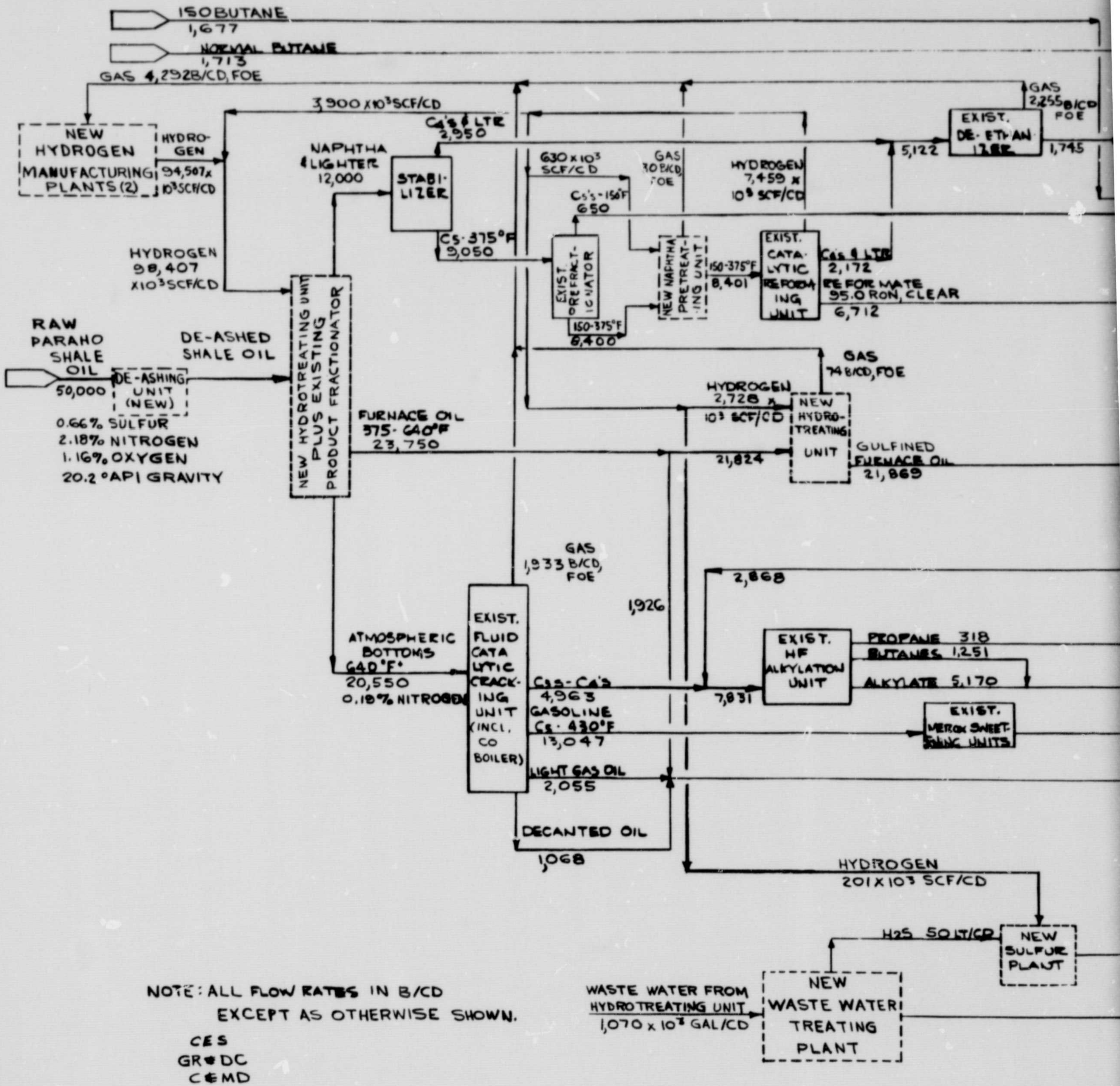

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FIGURE III-18

G REFINERY CHARGING SURFACE RETORTED SHALE OIL

JRBINE FUEL PRODUCTION - CASE 3.10

SHALE OIL PLUS FLUID CATALYTIC CRACKING OF RESIDUUM

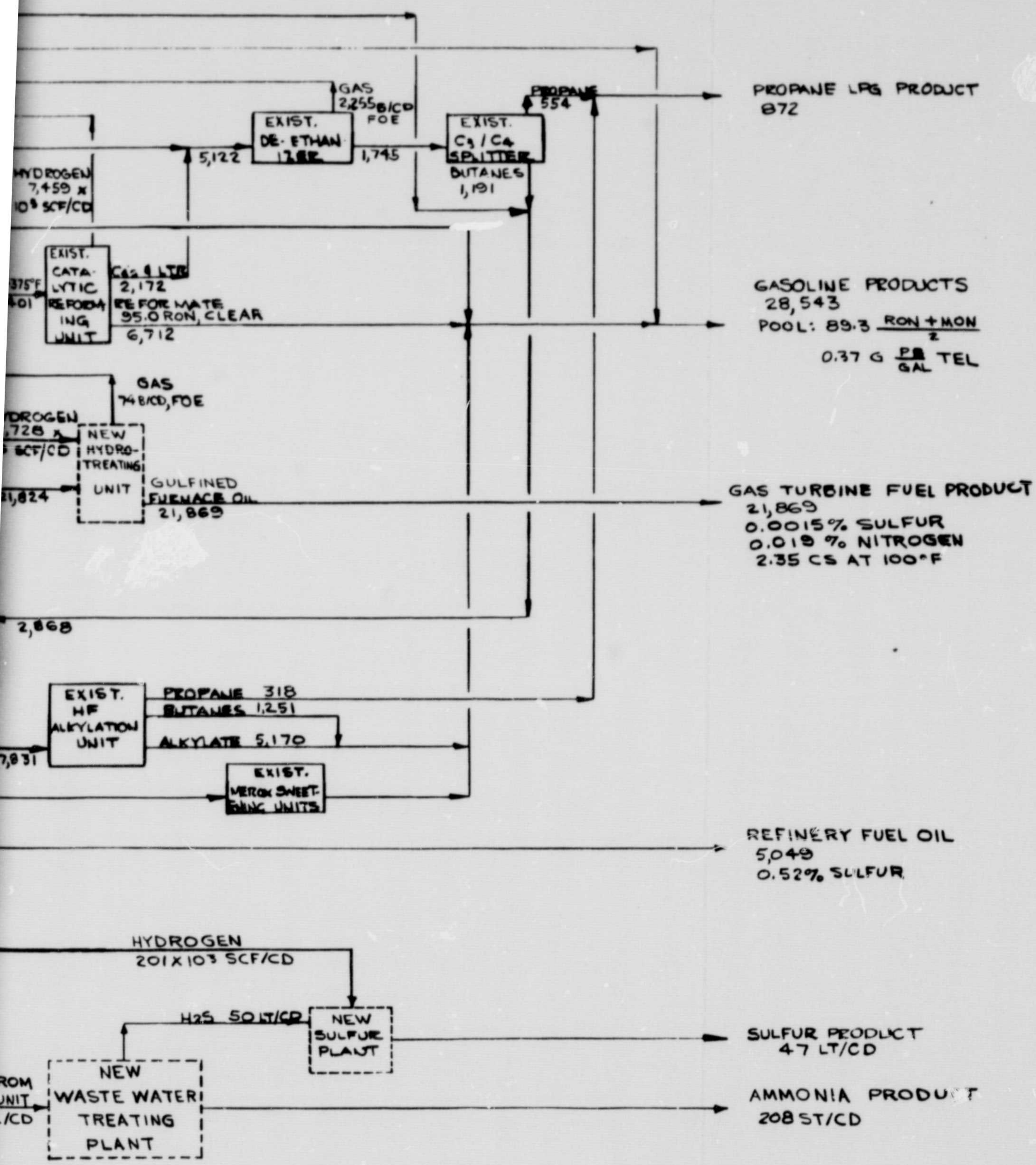

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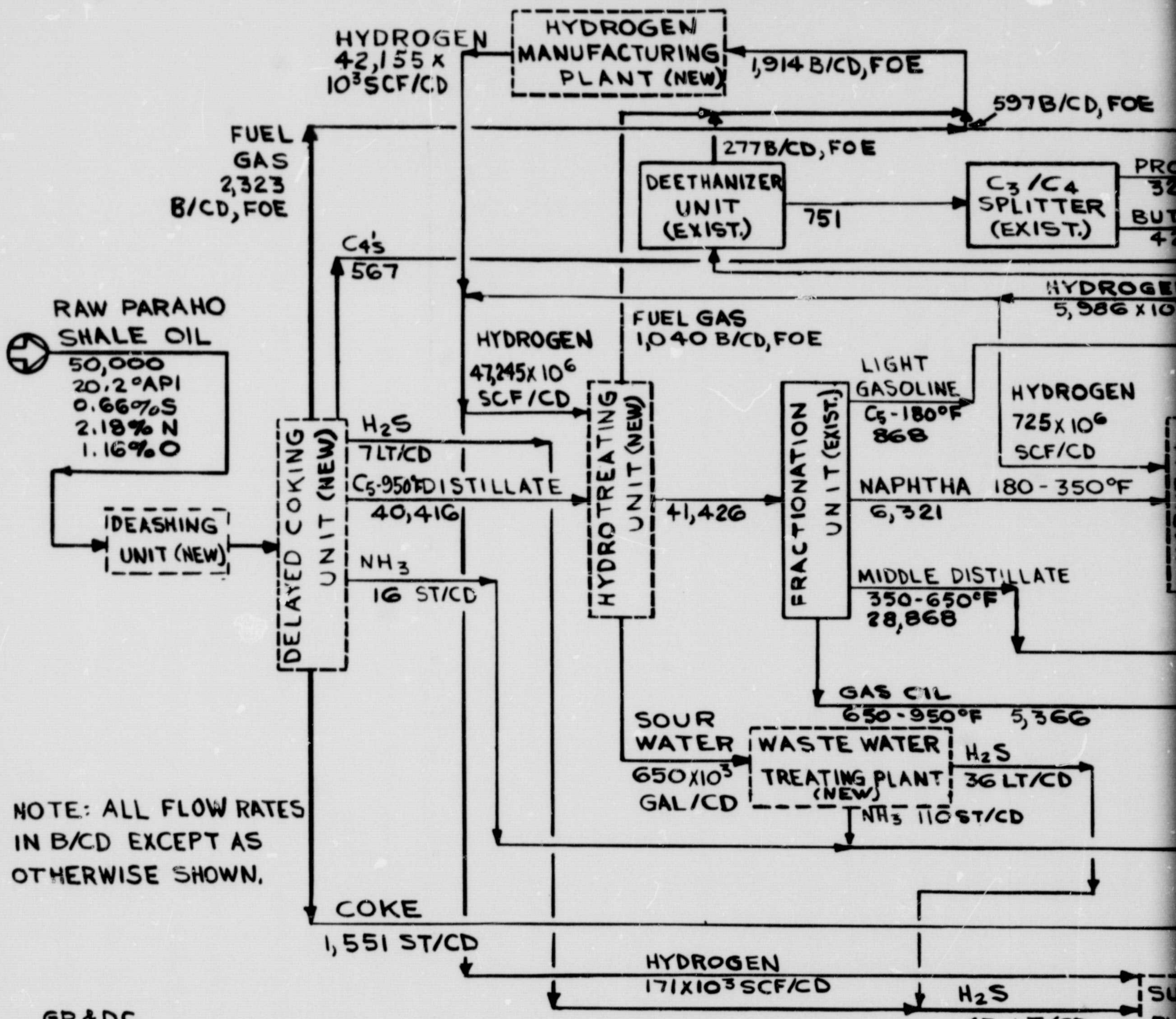
FIGURE III-19
REPRESENTATIVE EXISTING REFINERY CHARGING SU
PRODUCTION ON GAS TURBINE FUEL -
DELAYED COKING OF RAW SHALE



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III-19
HARGING SURFACE RETORTED SHALE OIL
RBINE FUEL - CASE 3.30
RAW SHALE OIL PLUS HYDROTREATING OF COKER DISTILLATE

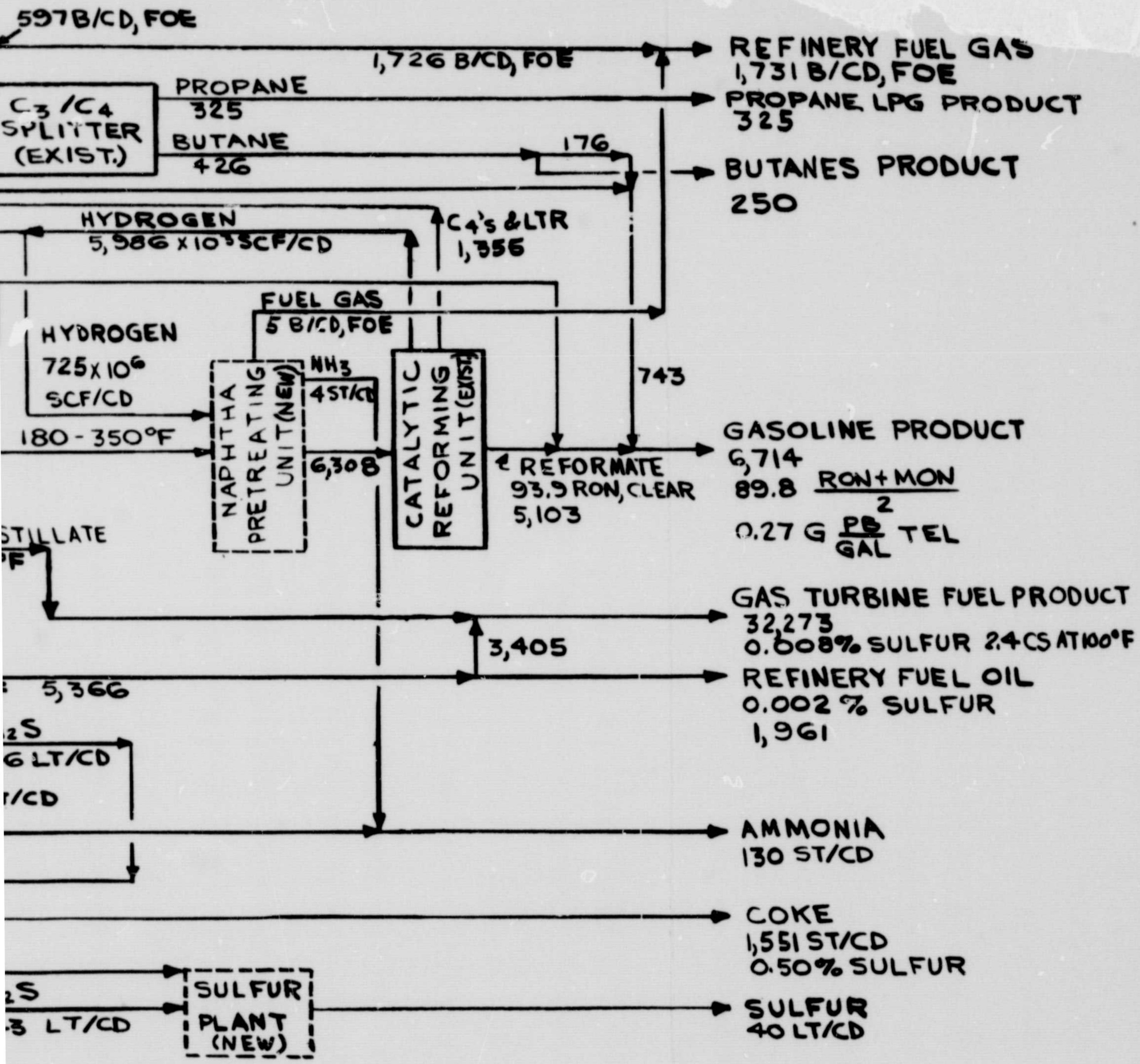

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FIGURE III-20
REPRESENTATIVE EXISTING REFINERY CHARGING MODIFI
GAS TURBINE FUEL PRODUCTION – CAS
SEVERE HYDROTREATING OF RAW SHALE OIL PLUS FLUID CATALY

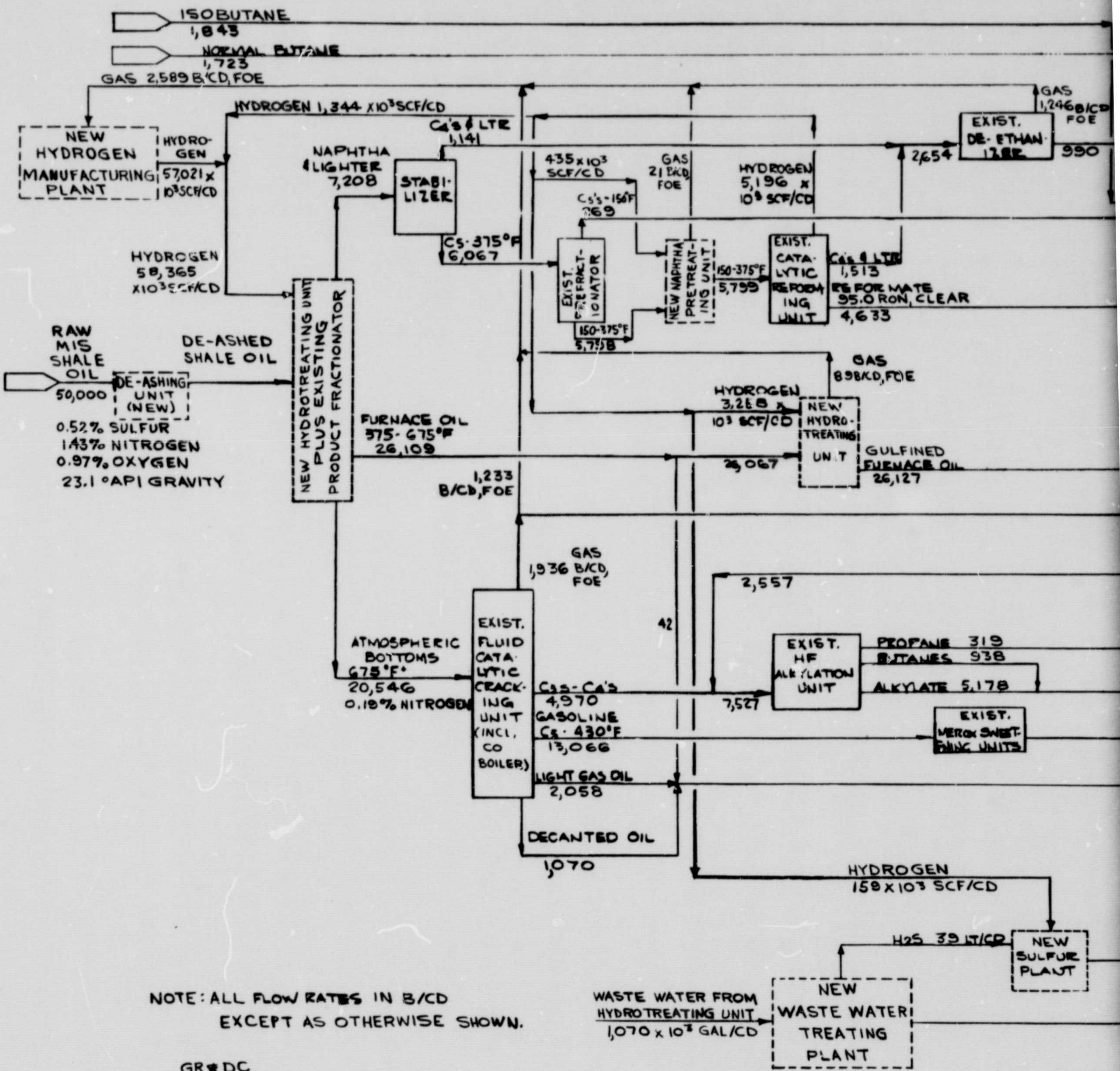

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FIGURE III-20

NG REFINERY CHARGING MODIFIED IN-SITU (MIS) RETORTED SHALE OIL

TURBINE FUEL PRODUCTION – CASE 4.10

W SHALE OIL PLUS FLUID CATALYTIC CRACKING OF RESIDUUM

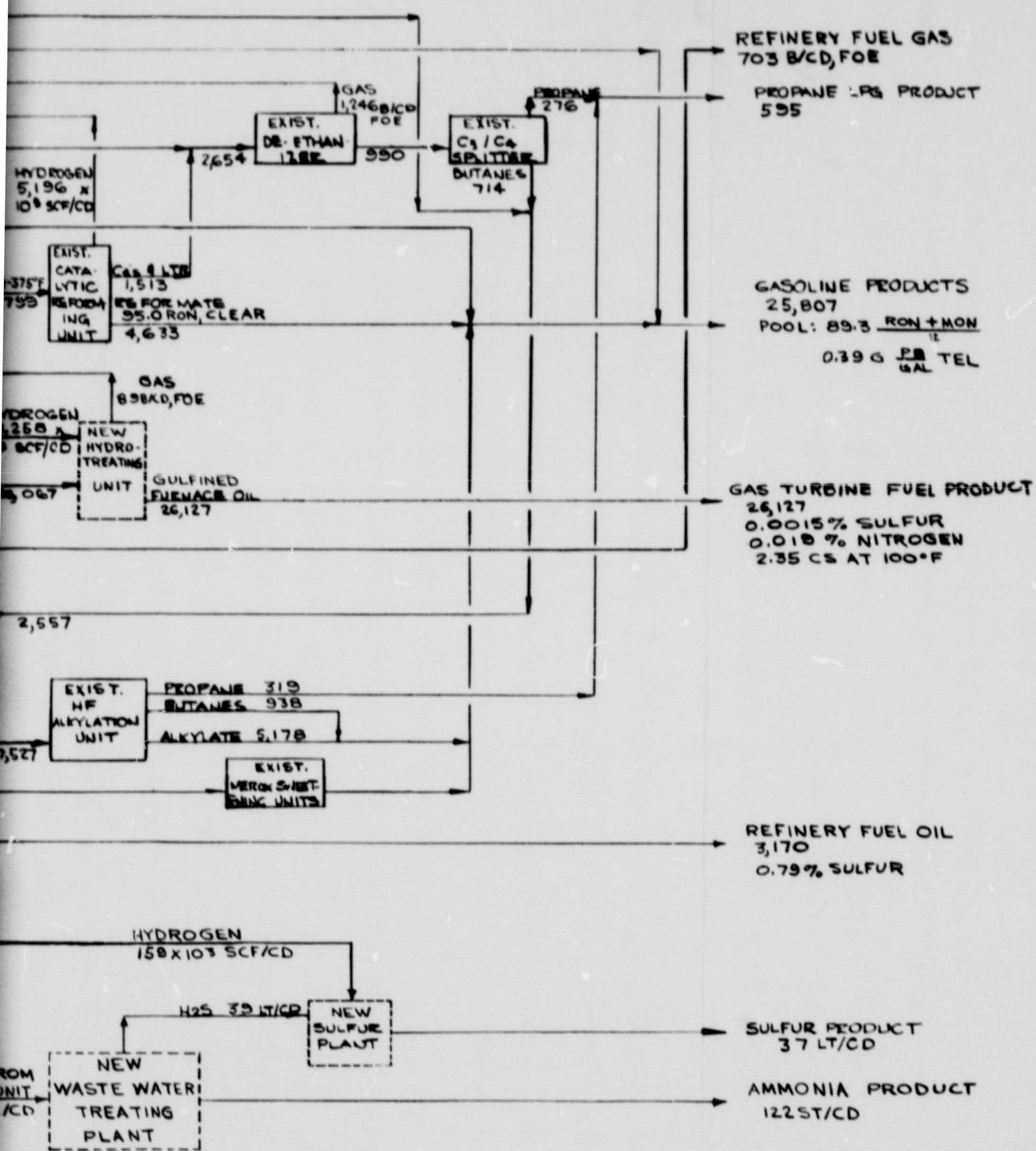

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FIGURE IV-

SYNCRUDE PRICING CASE: EASTERN CO

CASE 1000: HIGH-SEVERITY HYDROTRE

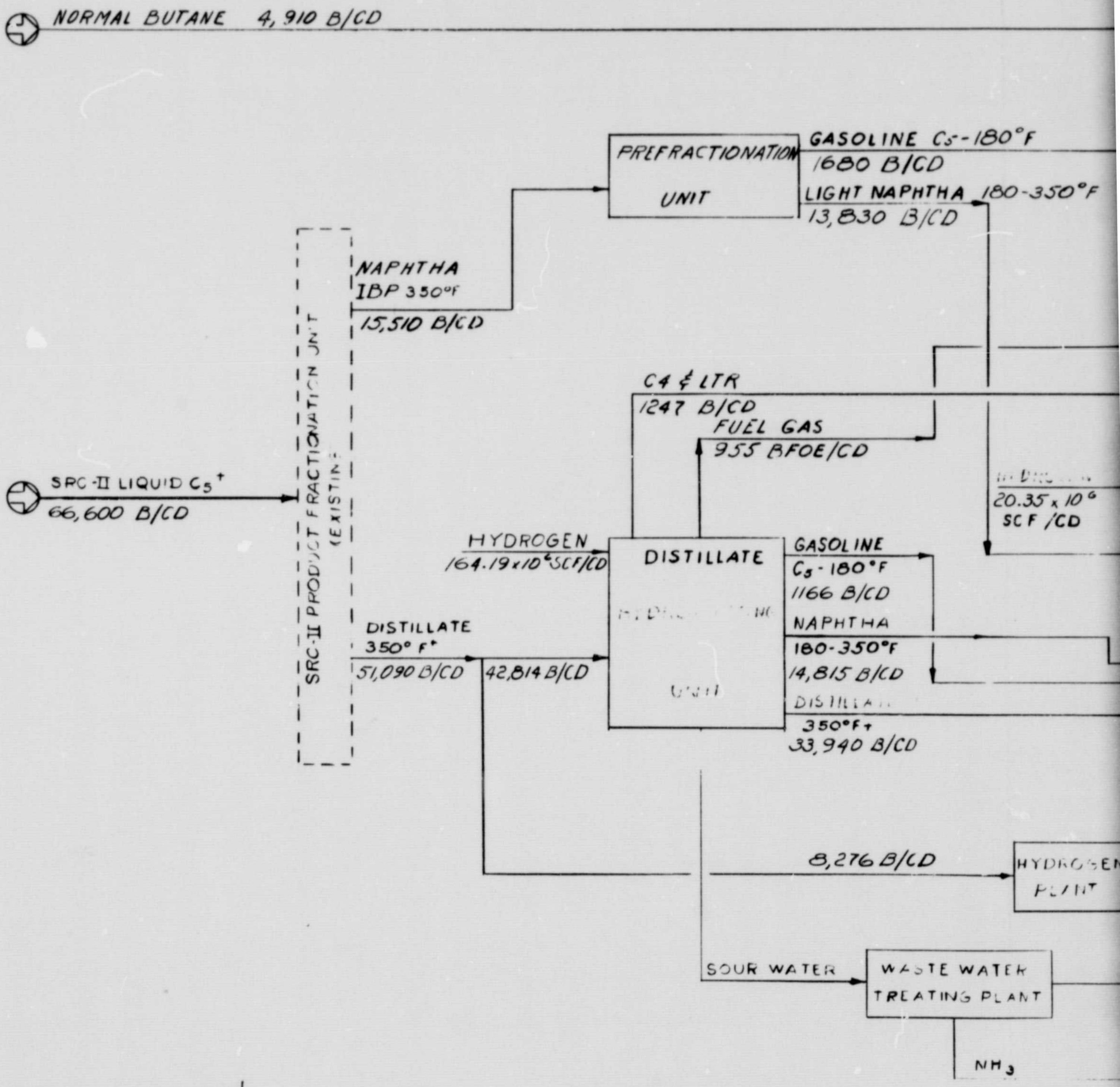

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FIGURE IV-1

ASE: EASTERN COAL LIQUID (SRC-II)

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VERITY HYDROTREATING OF SRC-II DISTILLATE

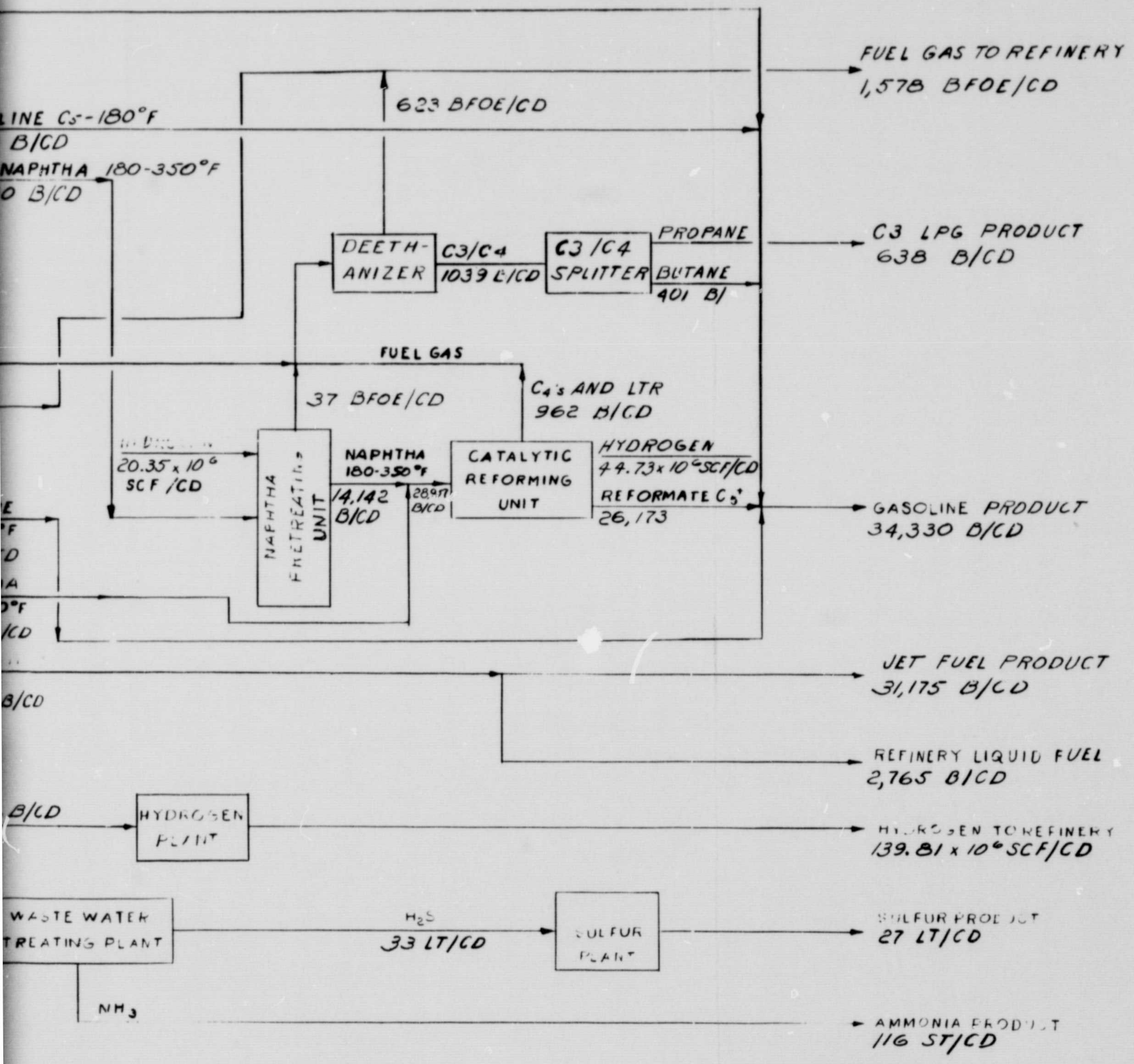

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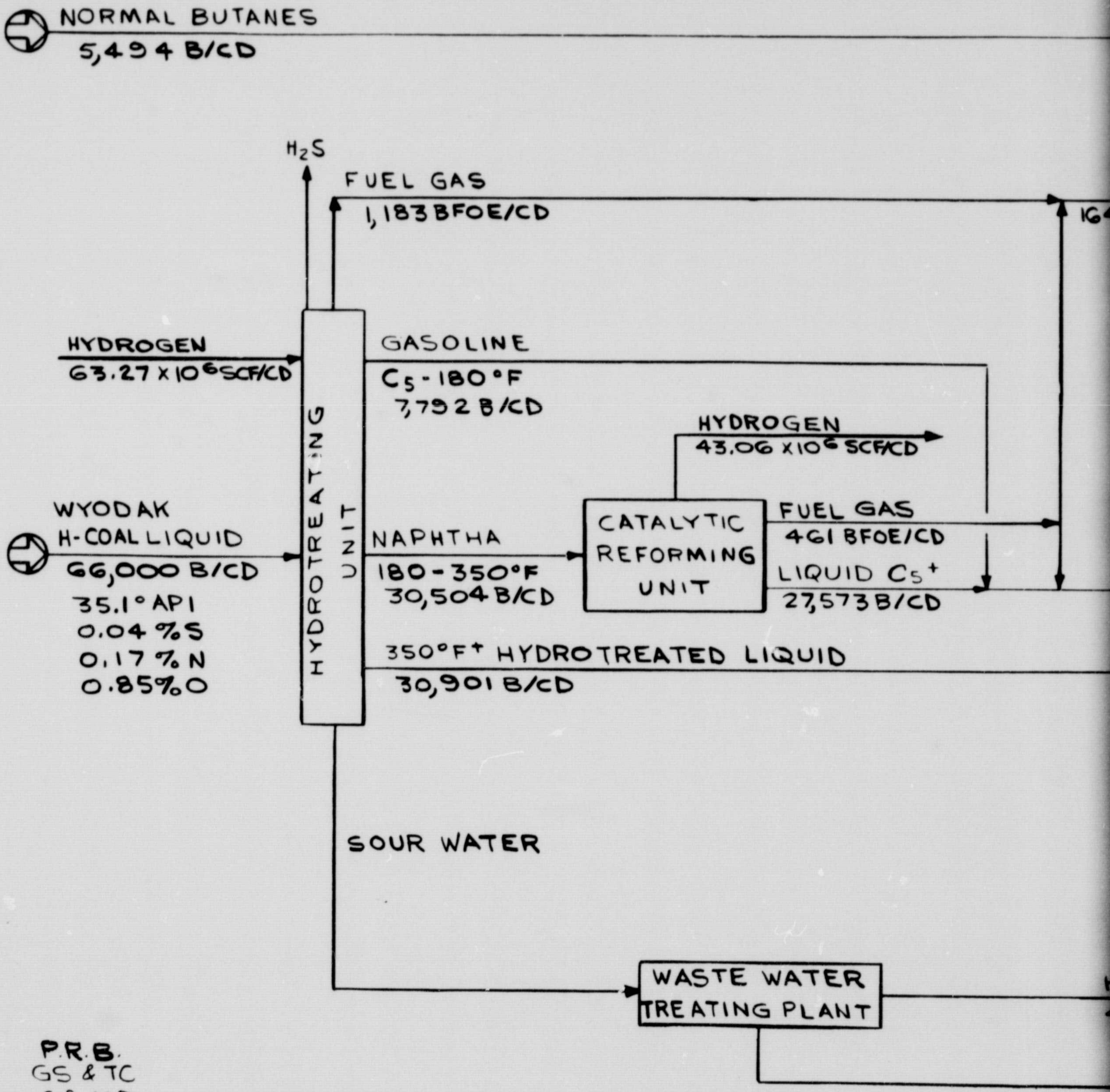
FIGURE IV-

SYNCRUDE PRICING CASE: WESTERN COAL

CASE 2000: HYDROTREATING OF



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GURE IV-2
RN COAL LIQUID (H-COAL)

ATING OF WYODAK H-COAL LIQUID AT MODERATE SEVERITY

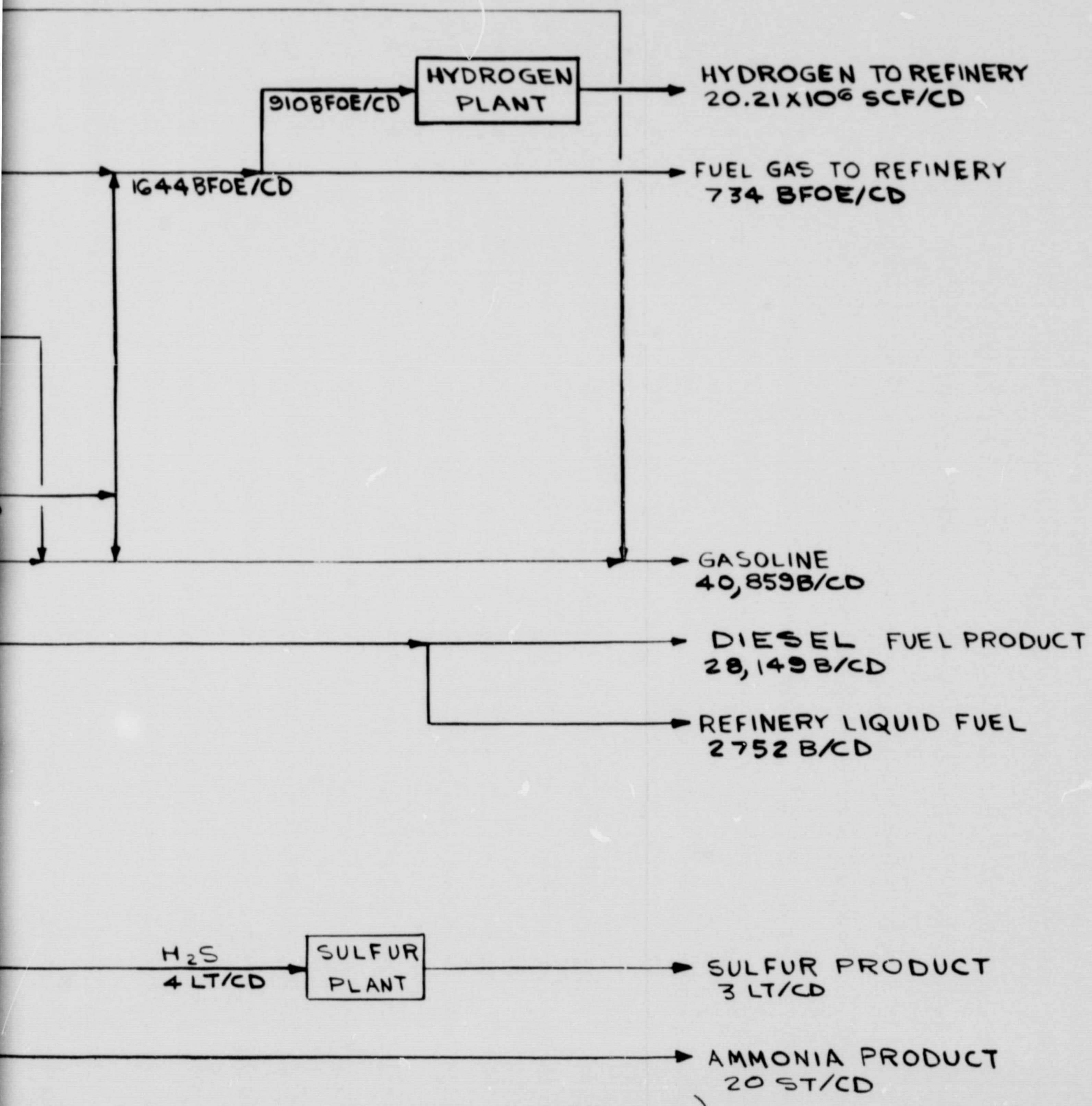

FIGURE IV-3

SYNCRUDE PRICING CASE: SURFACE-RETORTED SHALE OIL (P

CASE 3000: HIGH SEVERITY HYDROTREATING PLUS FCC OF

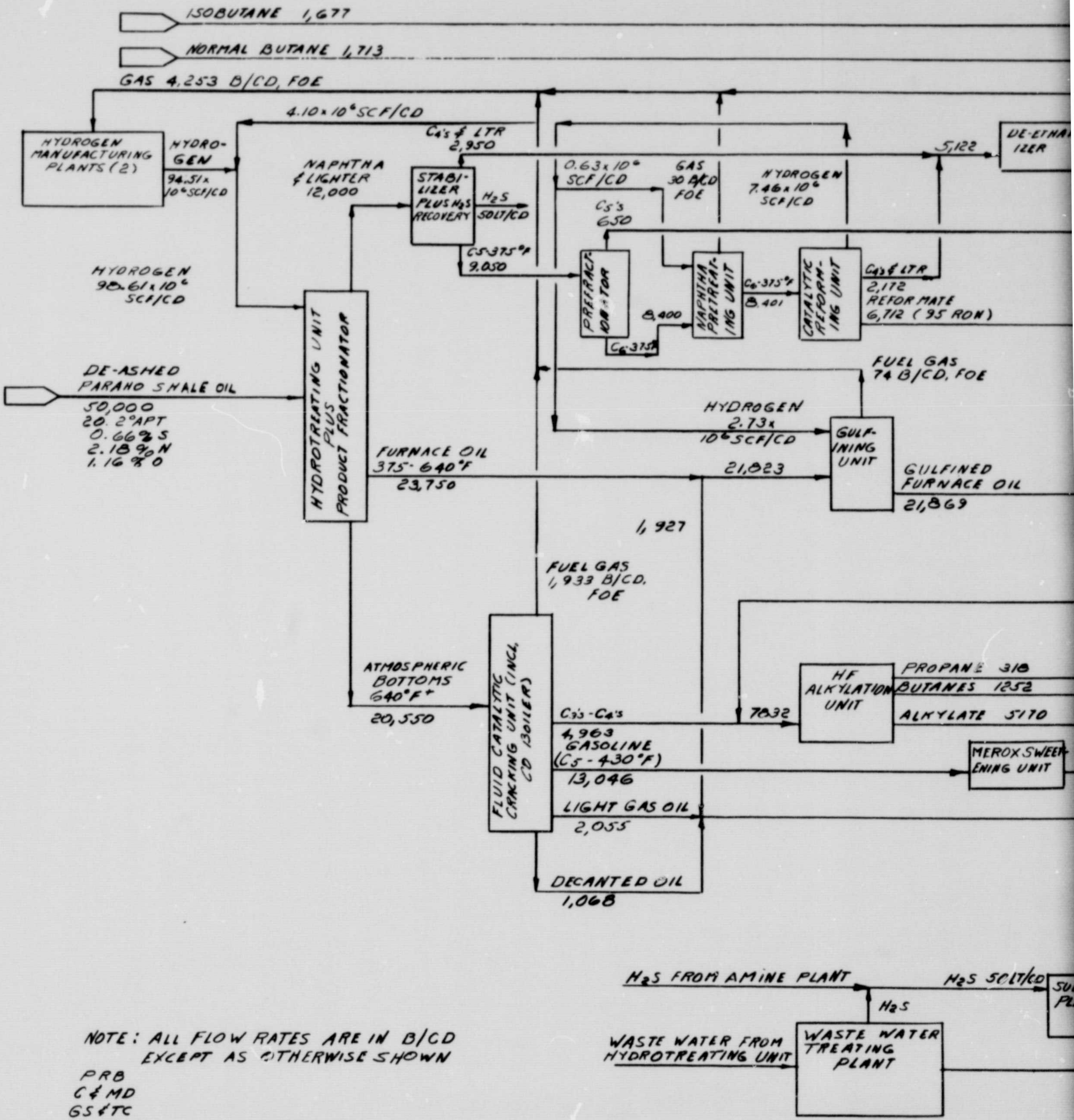

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FIGURE IV-3
: SURFACE-RETORTED SHALE OIL (PARAHO)
TY HYDROTREATING PLUS FCC OF 640°F+ BOTTOM

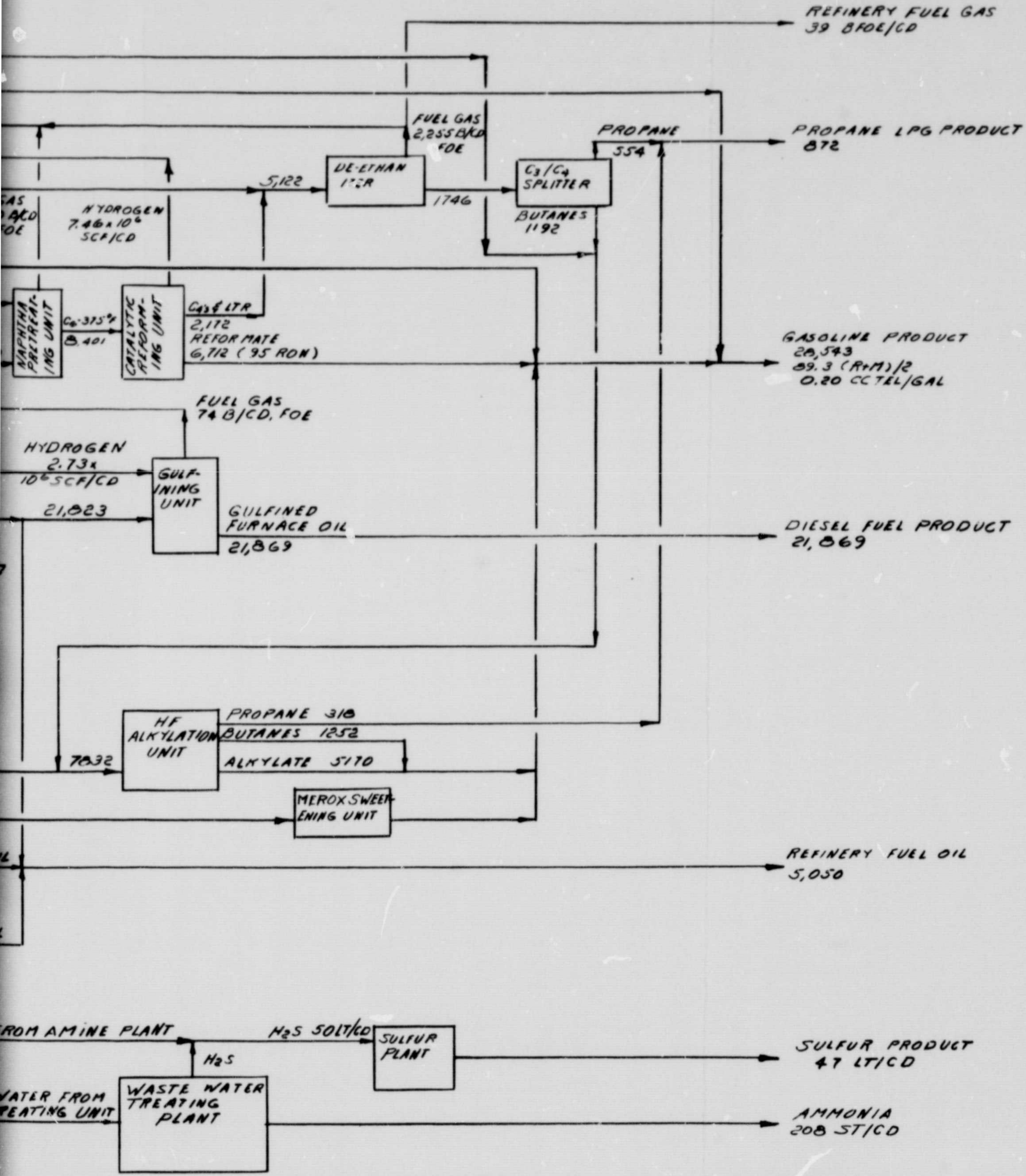

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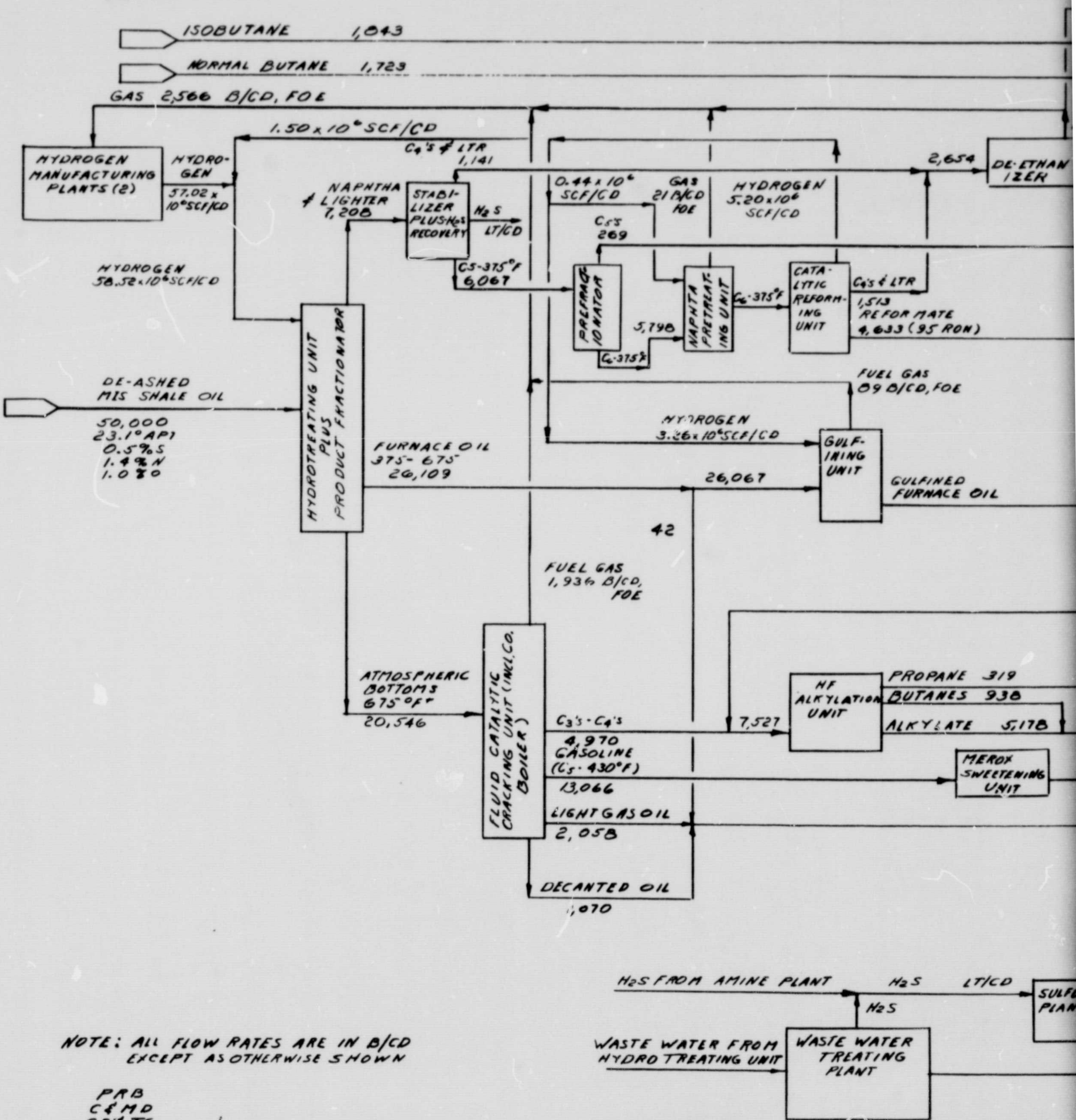
FIGURE IV-4

SYNCRUDE PRICING CASE: MODIFIED IN-SITU

CASE 4000: HIGH SEVERITY HYDROTREATING



NOTE: ALL FLOW RATES ARE IN B/CD
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FIGURE IV-4

...NG CASE: MODIFIED IN-SITU SHALE OIL (OCCIDENTAL)

...SEVERITY HYDROTREATING PLUS FCC OF 675°F+ BOTTOMS

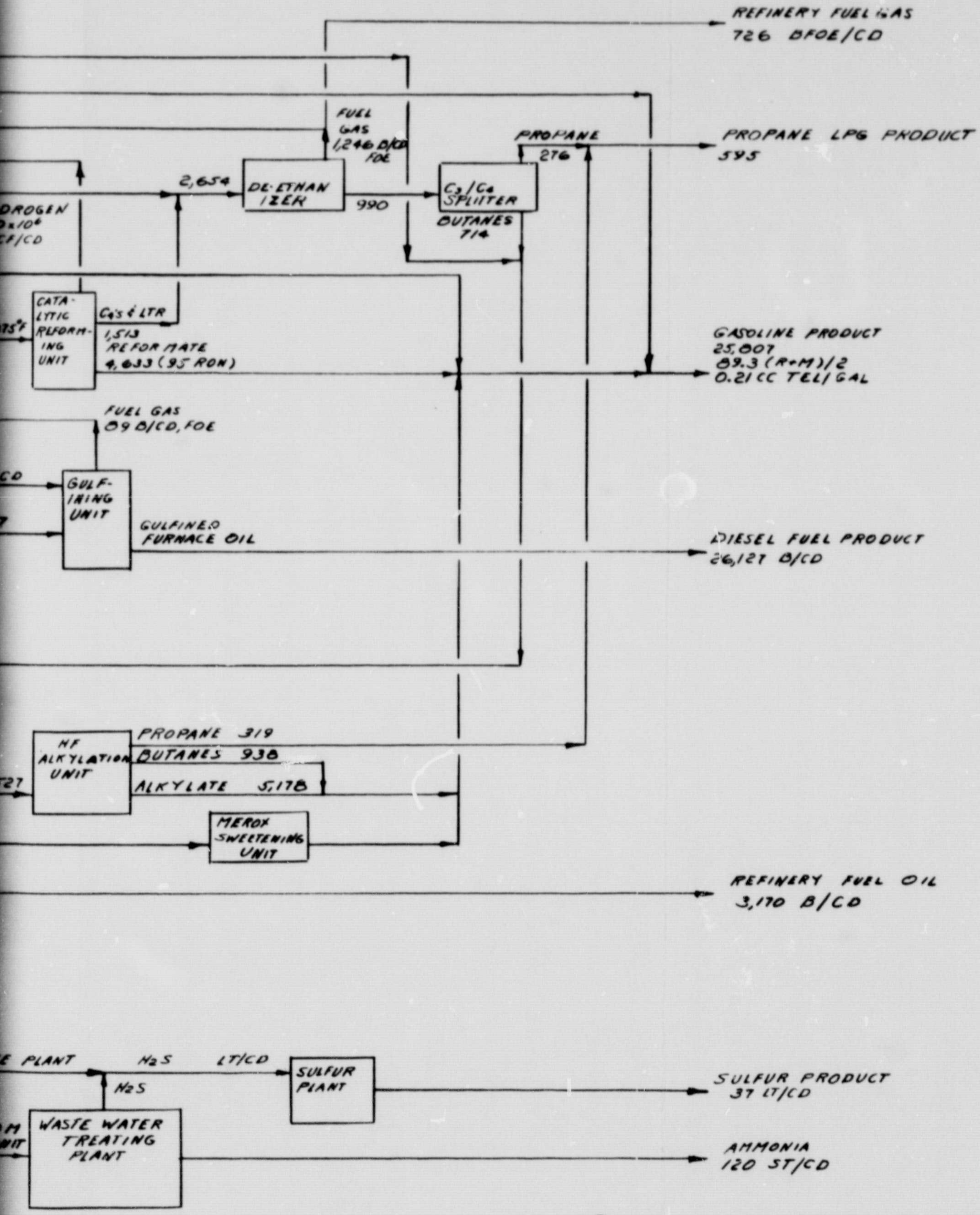

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FIGURE IV-5

UPGRADING OF EASTERN COAL LIQUID TO GAS

CASE 1010 HYDROTREATING OF SRC-

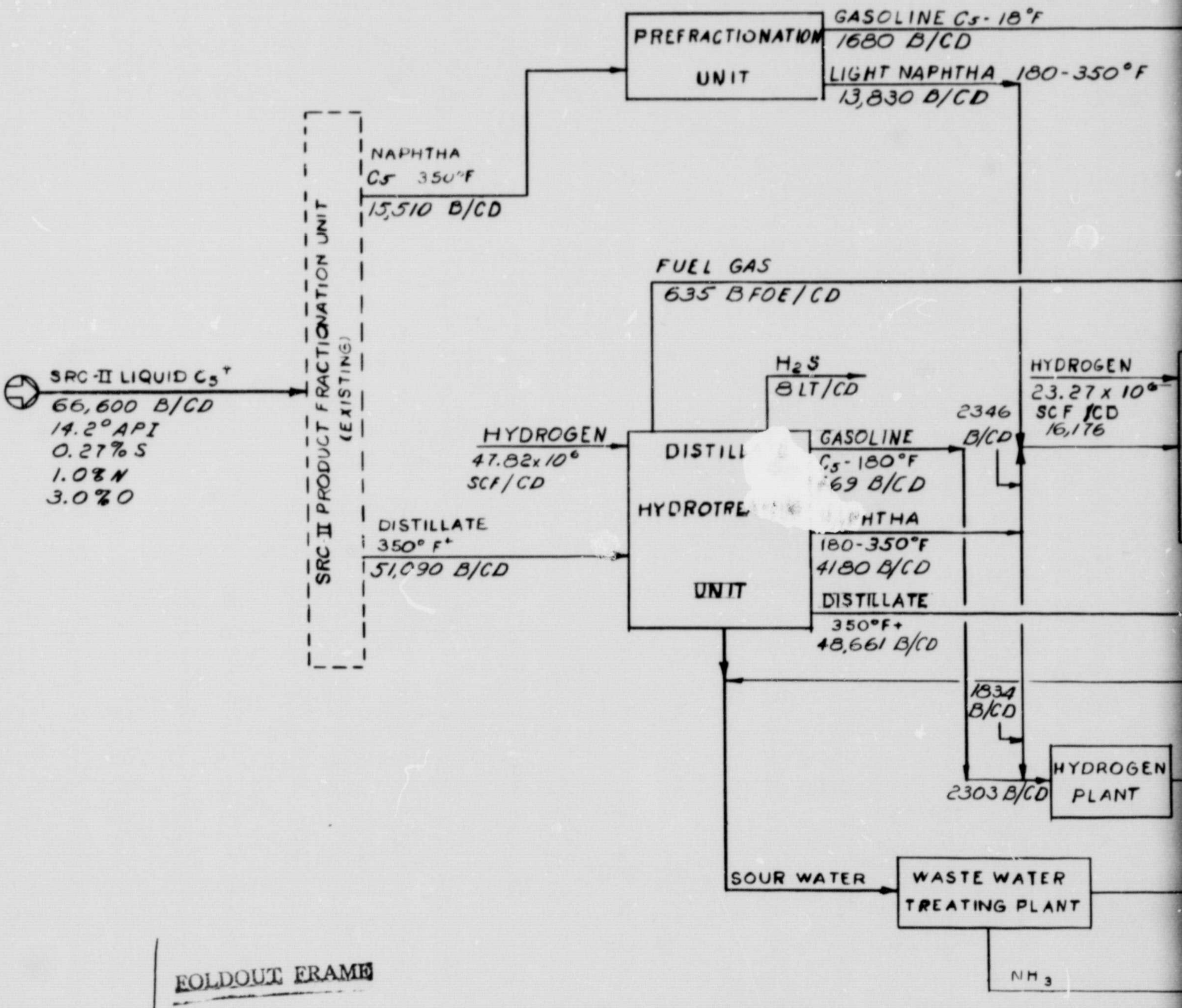

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FIGURE IV-5

COAL LIQUID TO GAS TURBINE FUEL

DROTREATING OF SRC-II DISTILLATE AT MODERATE SEVERITY

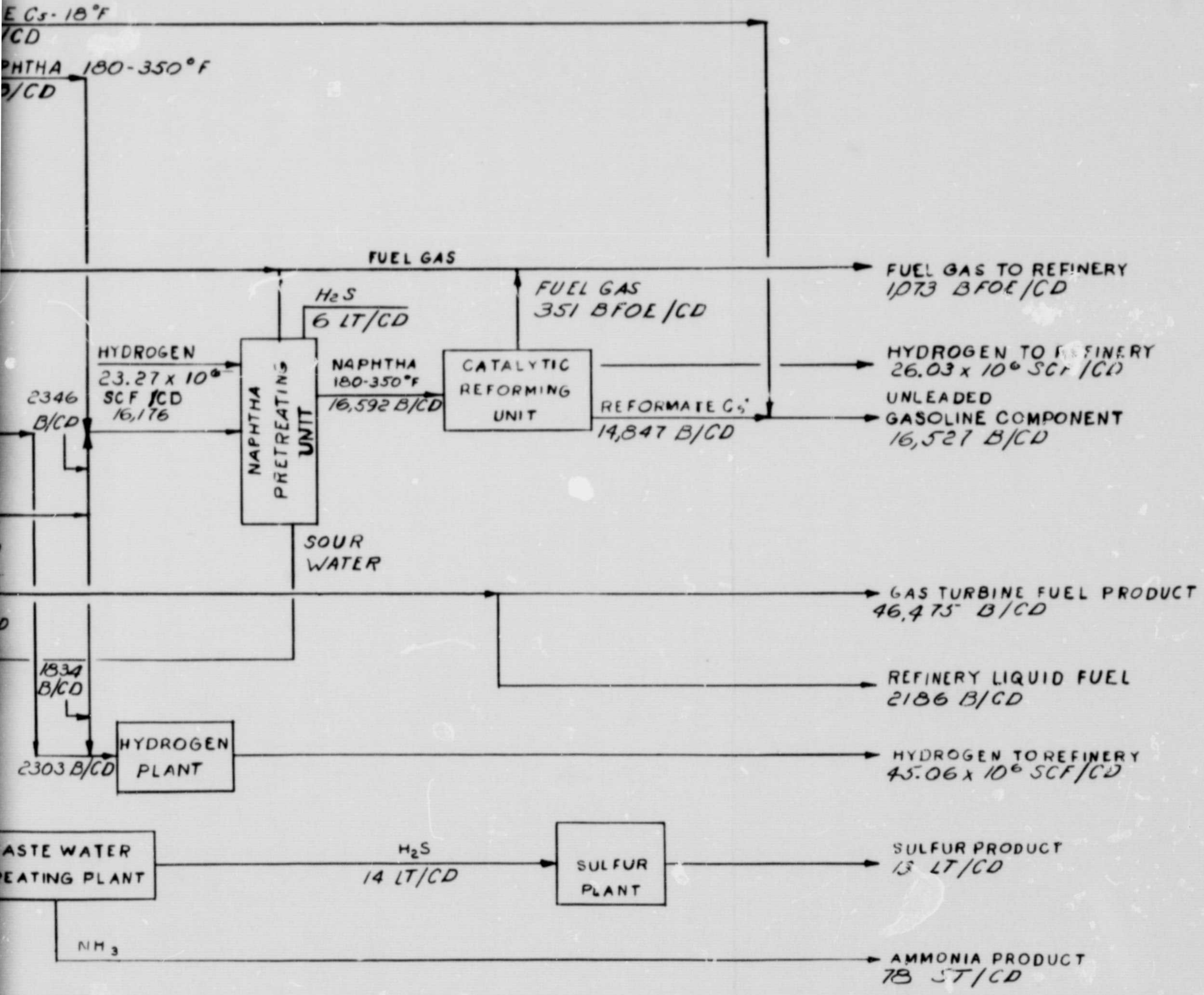

FIGURE IV-6

UPGRADING OF EASTERN COAL LIQUID T

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CASE 1011 HYDROTREATING OF SRC-II D

PARTIAL OXIDATION HYD

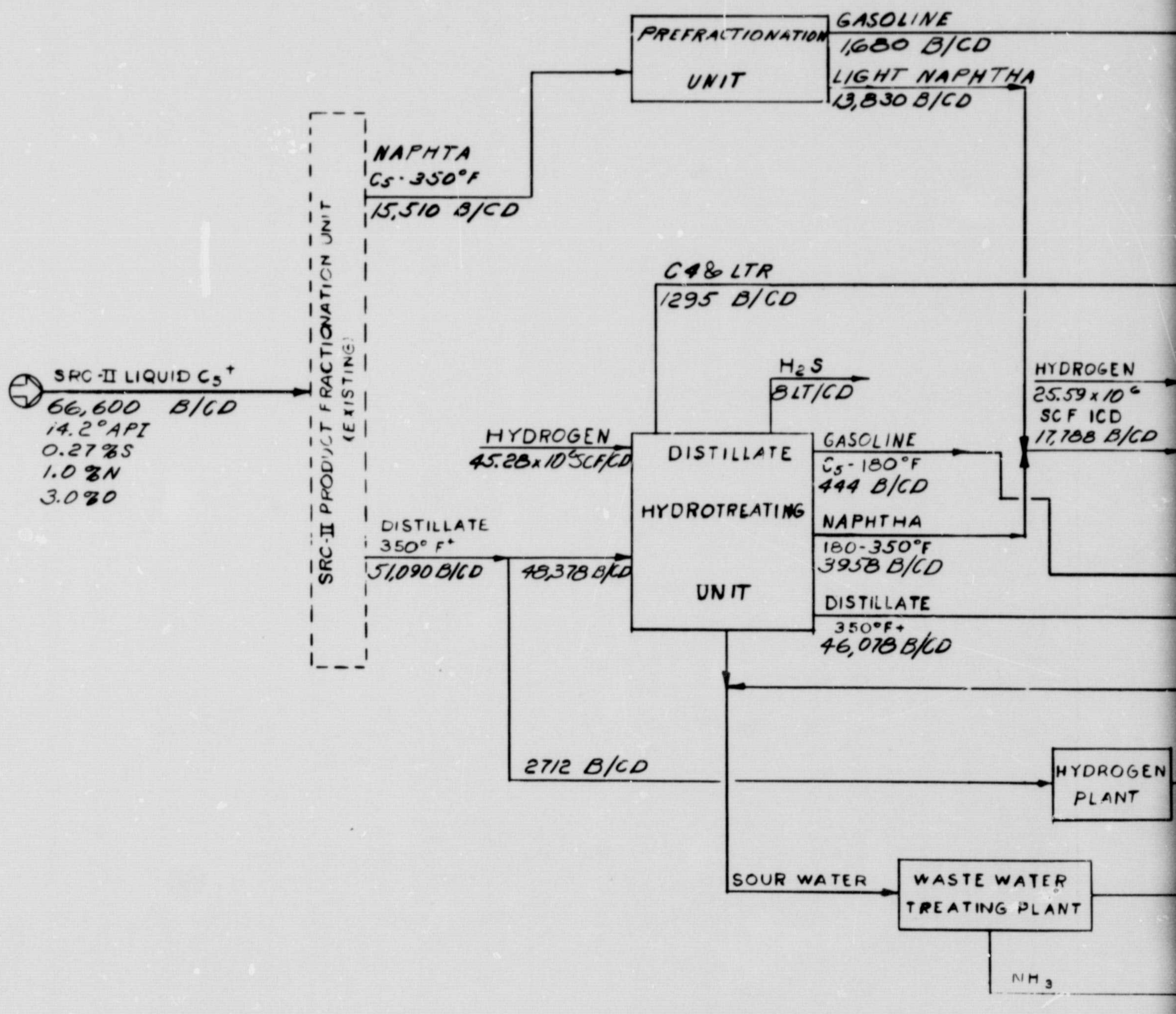

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FIGURE IV-6
OAL LIQUID TO GAS TURBINE FUEL

OF SRC-II DISTILLATE AT MODERATE SEVERITY;
IDATION HYDROGEN MANUFACTURE

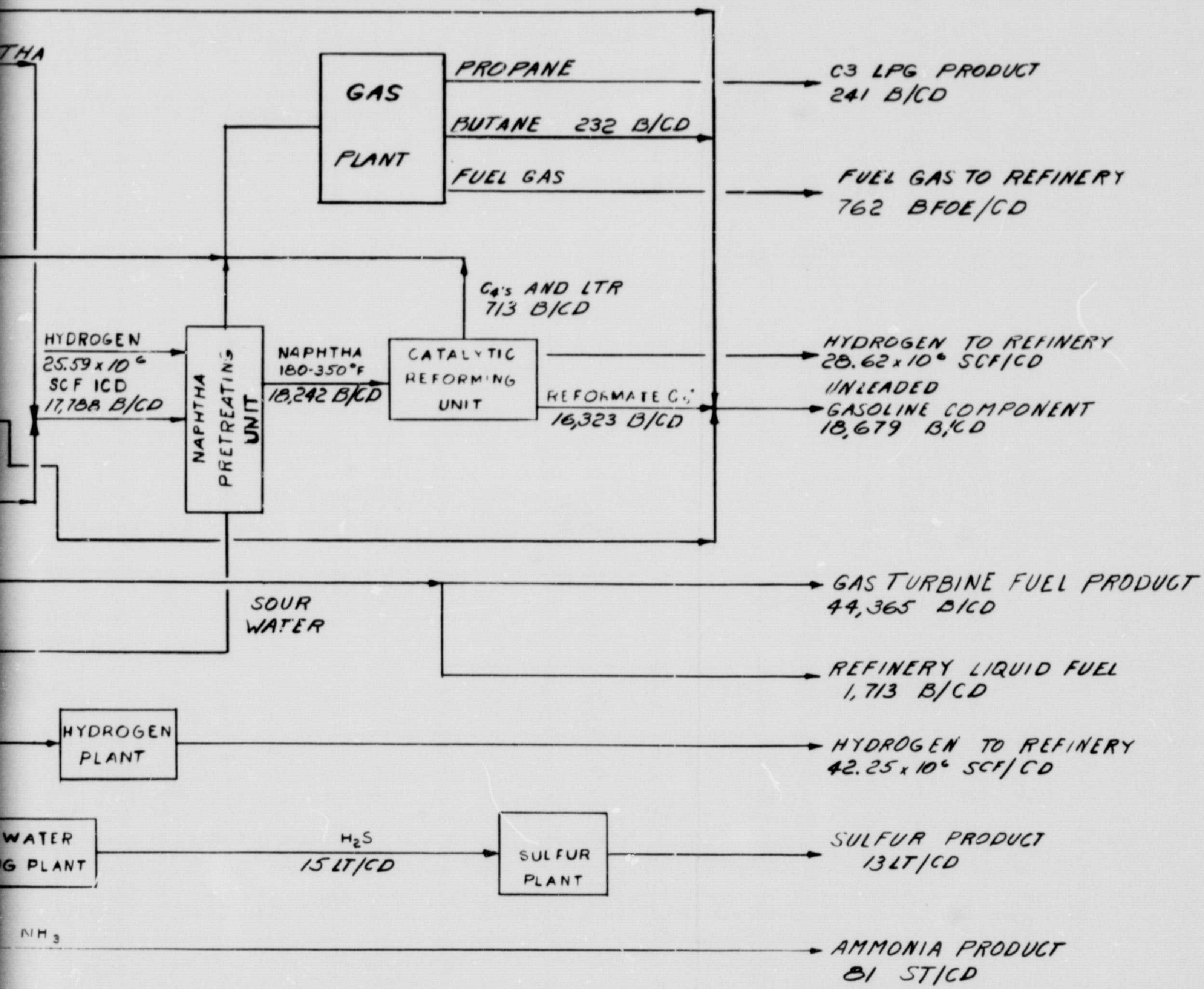

FIGURE IV-

UPGRADING OF EASTERN COAL LIQUID TO

CASE 1020 HYDROTREATING OF S

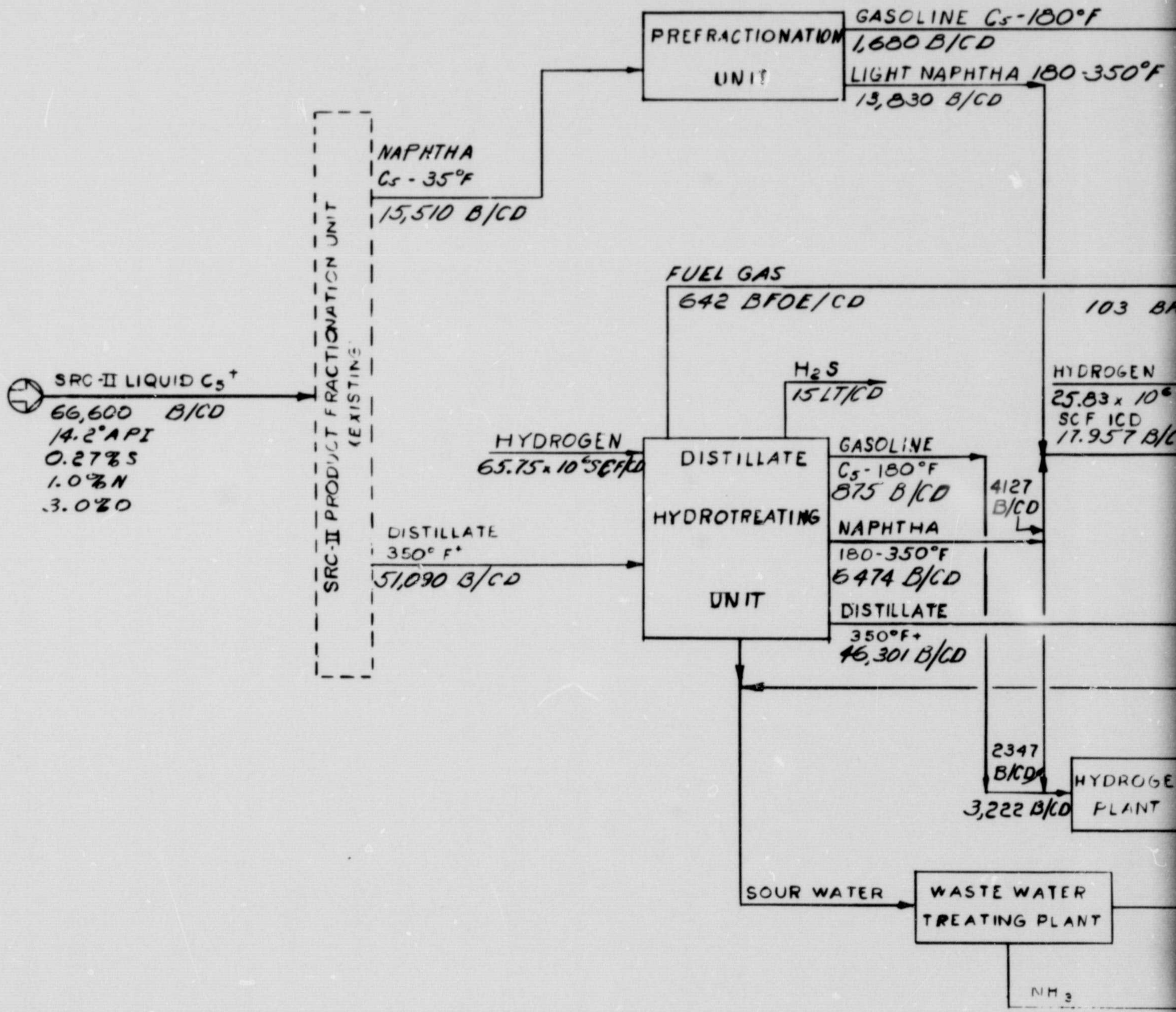

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FIGURE IV-7

AL LIQUID TO GAS TURBINE FUEL

REATING OF SRC-II DISTILLATE AT INTERMEDIATE SEVERITY

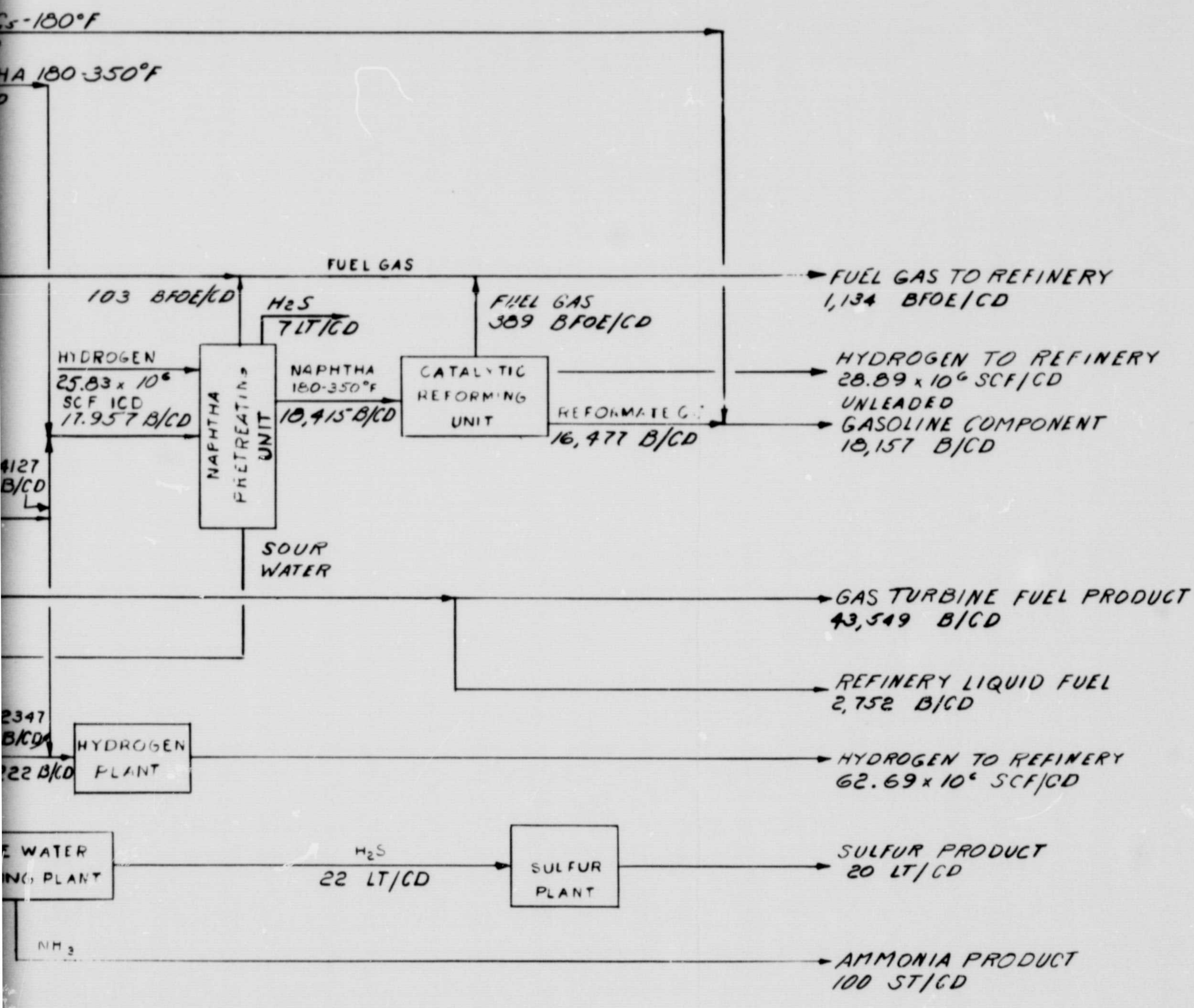

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FIGURE IV-8

UPGRADING OF EASTERN COAL LIQUID TO GAS

CASE 1030 HYDROTREATING OF SRC-

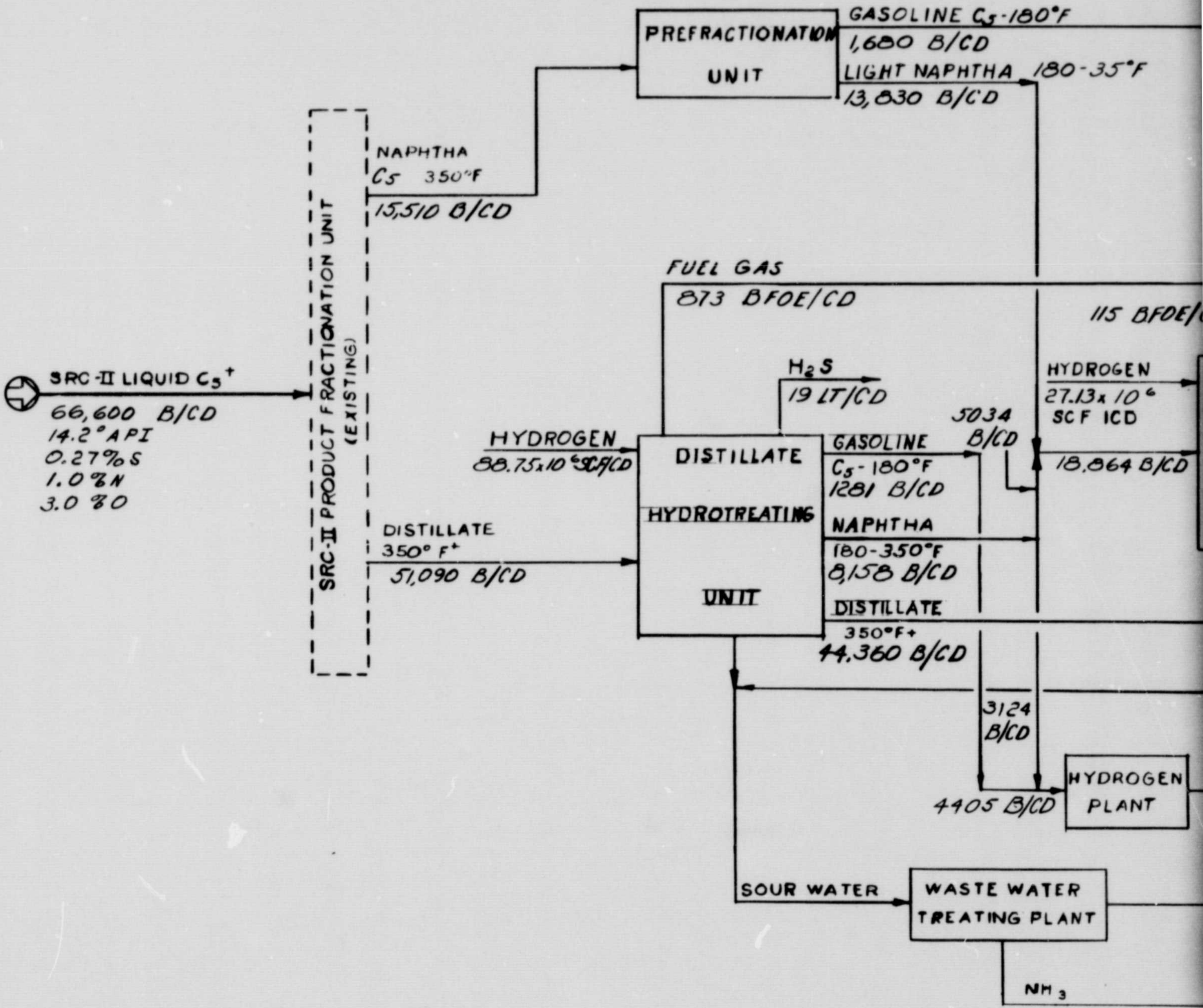

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FIGURE IV-8

OAL LIQUID TO GAS TURBINE FUEL

OTREATING OF SRC-II DISTILLATE AT HIGH SEVERITY

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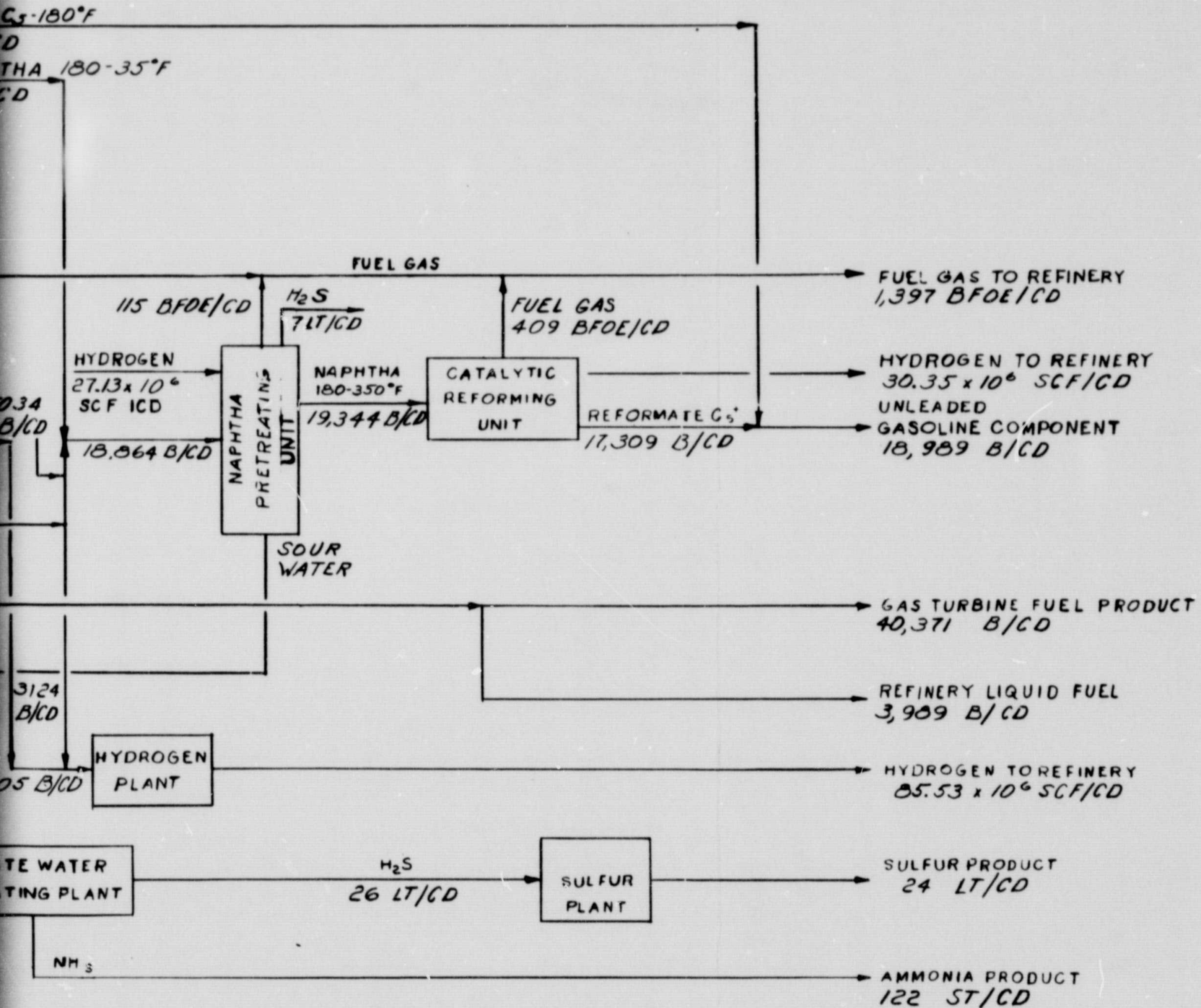

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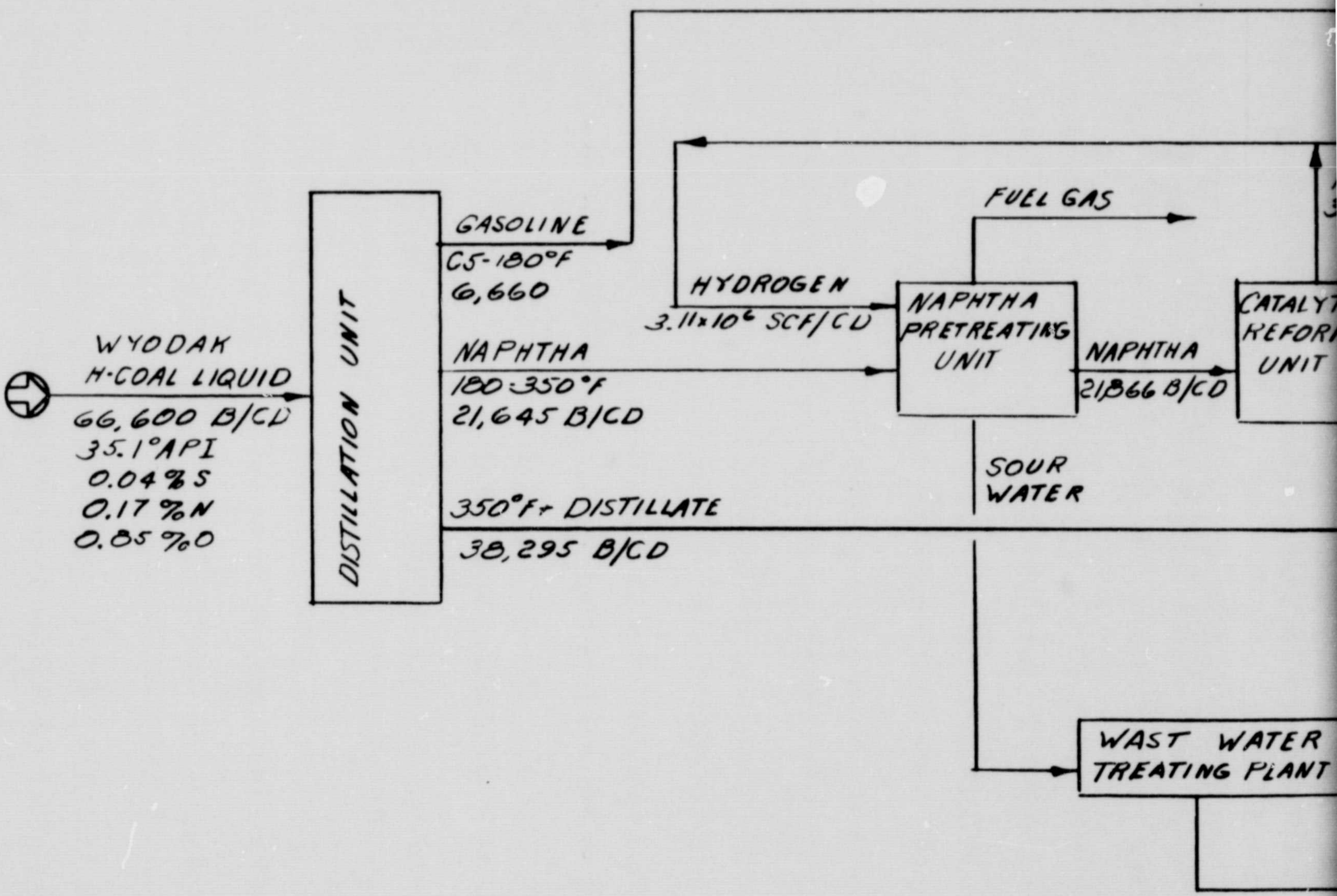
FIGURE IV 9

UPGRADING OF WESTERN COAL LIQUI

CASE 2010: HYDROTHEATING OF WYODAK



E IV 9

OAL LIQUID TO GAS TURBINE FUEL

F WYODAK H-COAL NAPHTHA ONLY; RAW 350°F+ TO GAS TURBINE FUEL

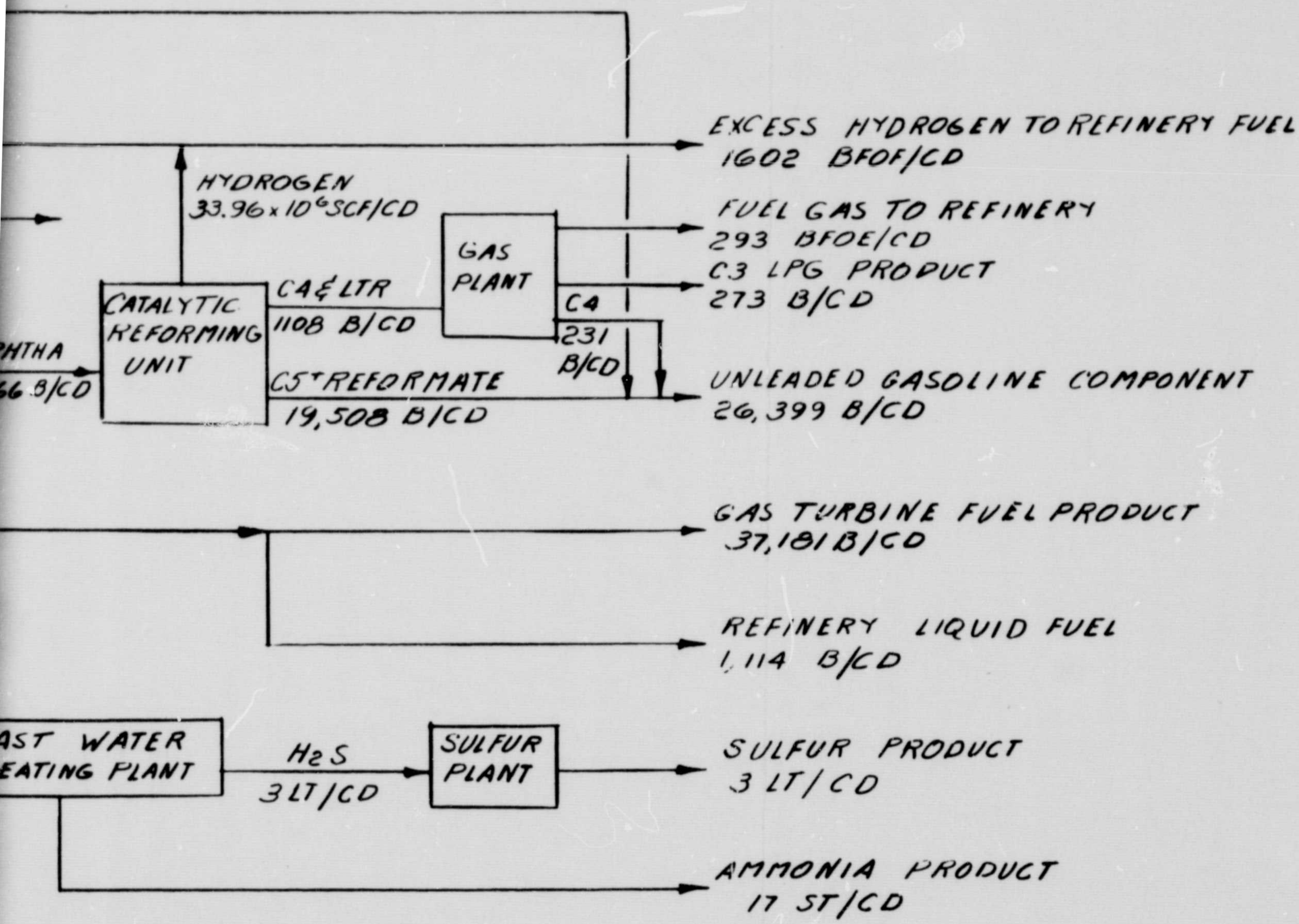


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FIGURE IV-

WESTERN COAL

CASE 2020: HYDROTREATING OF

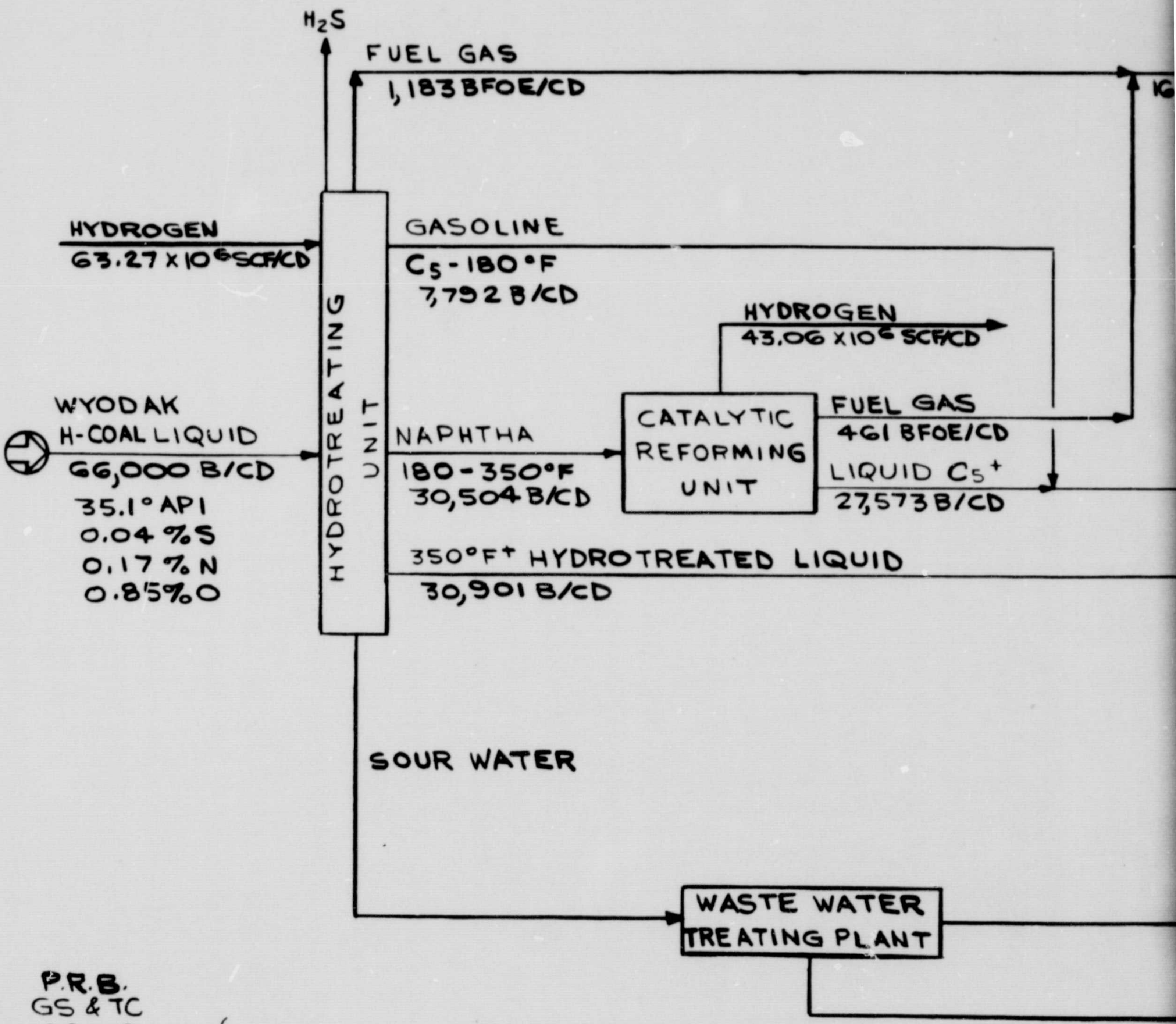

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FIGURE IV-10

ERN COAL LIQUID TO GAS TURBINE FUEL

EATING OF WYODAK H-COAL LIQUID

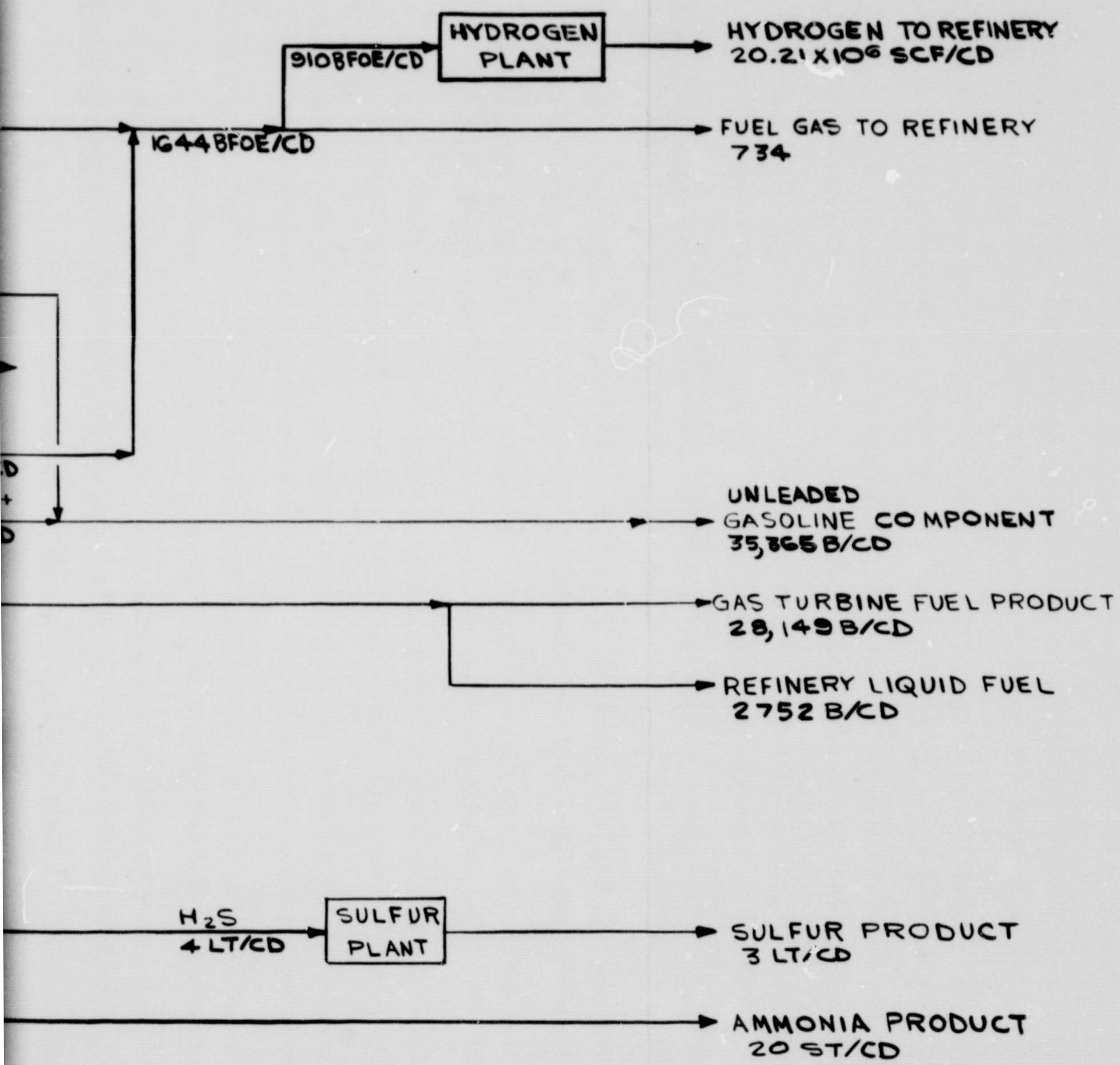
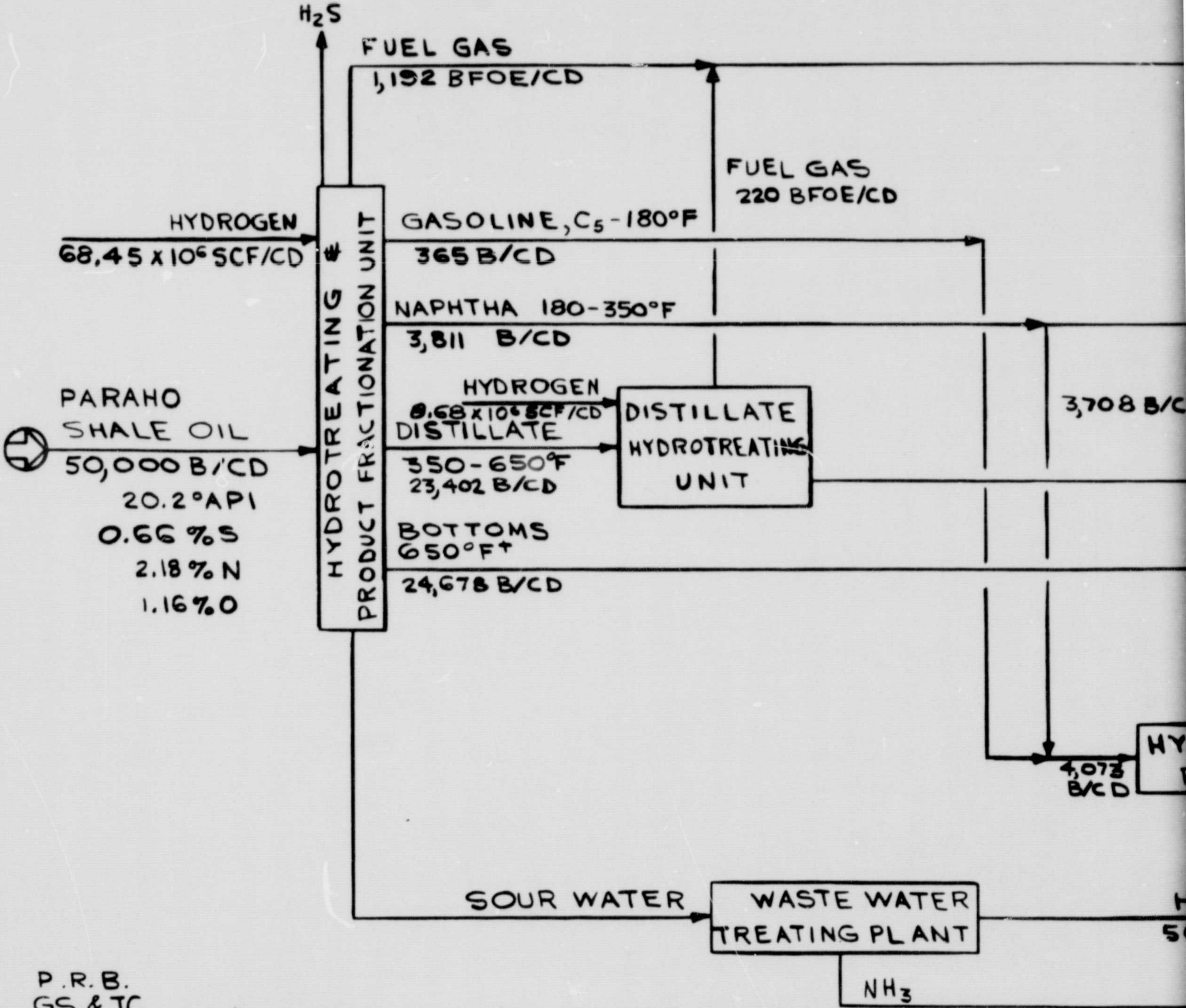


FIGURE IV-

UPGRADING OF SURFACE-RETORT

CASE 3010: HYDROTREATING OF
DISTILLATE TO DIESEL FUEL; S



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GURE IV- 11

L-RETORTED SHALE OIL TO GAS TURBINE FUEL

EATING OF PARAHO SHALE OIL AT MODERATE SEVERITY;
EL FUEL; STEAM REFORMING H_2 PLANT

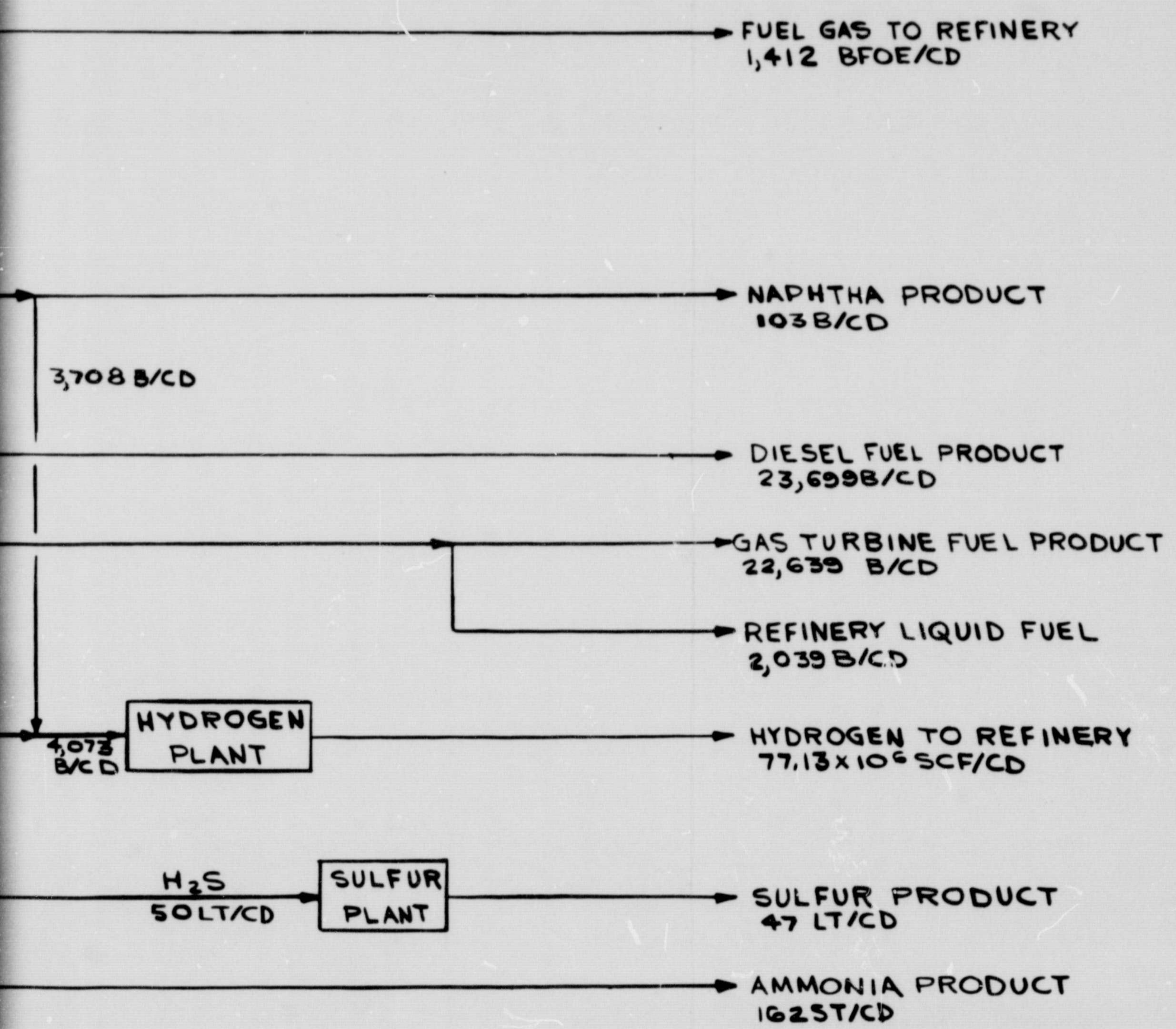
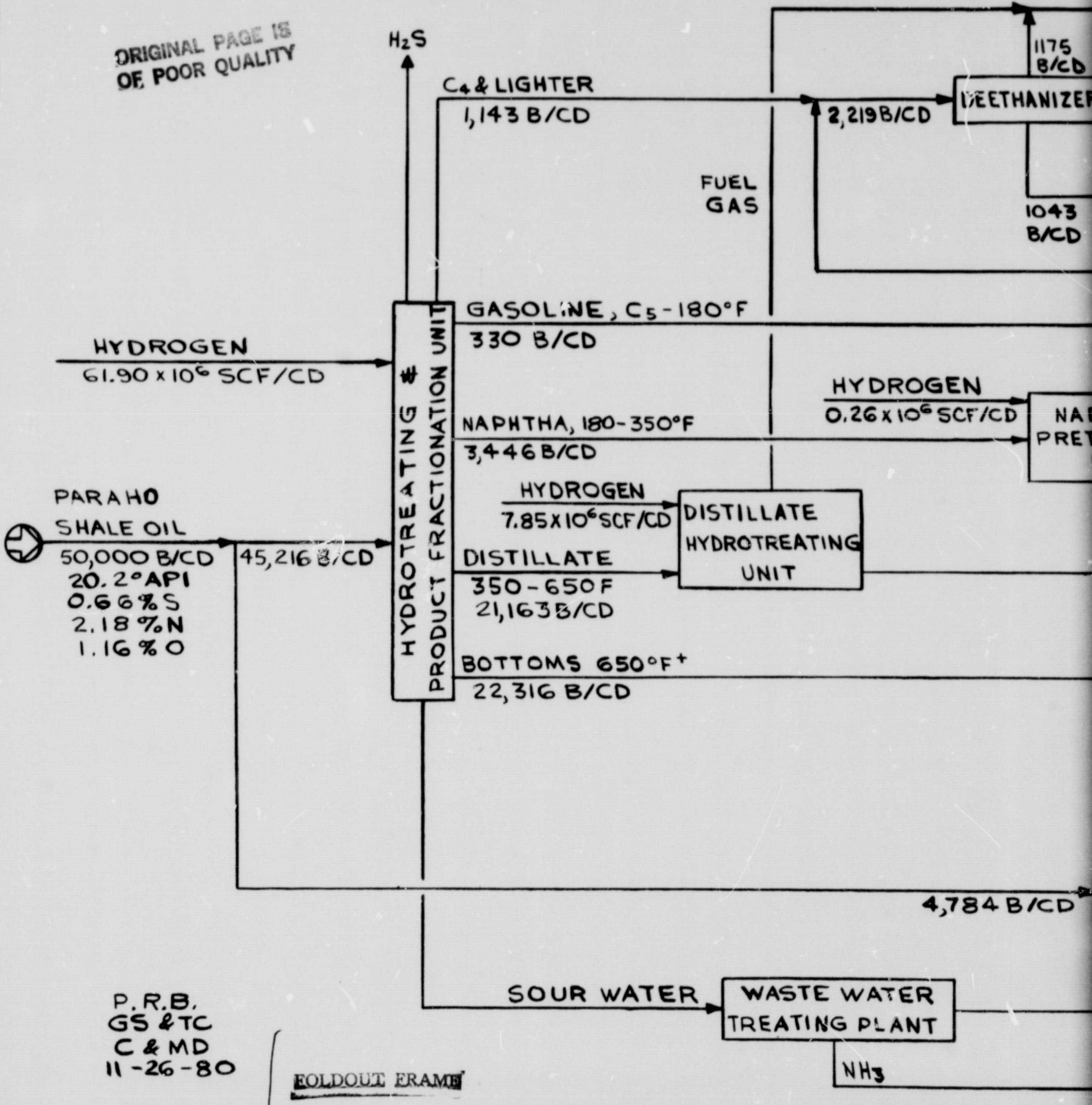


FIGURE IV-

UPGRADING OF SURFACE-RETORTED SHALE

CASE 3011 HYDROTREATING OF PARAHO SHALE OIL A

DISTILLATE TO DIESEL FUEL; PARTIAL OXIDA



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IGURE IV-12
ED SHALE OIL TO GAS TURBINE FUEL
ALE OIL AT MODERATE SEVERITY;
TIAL OXIDATION H_2 PLANT

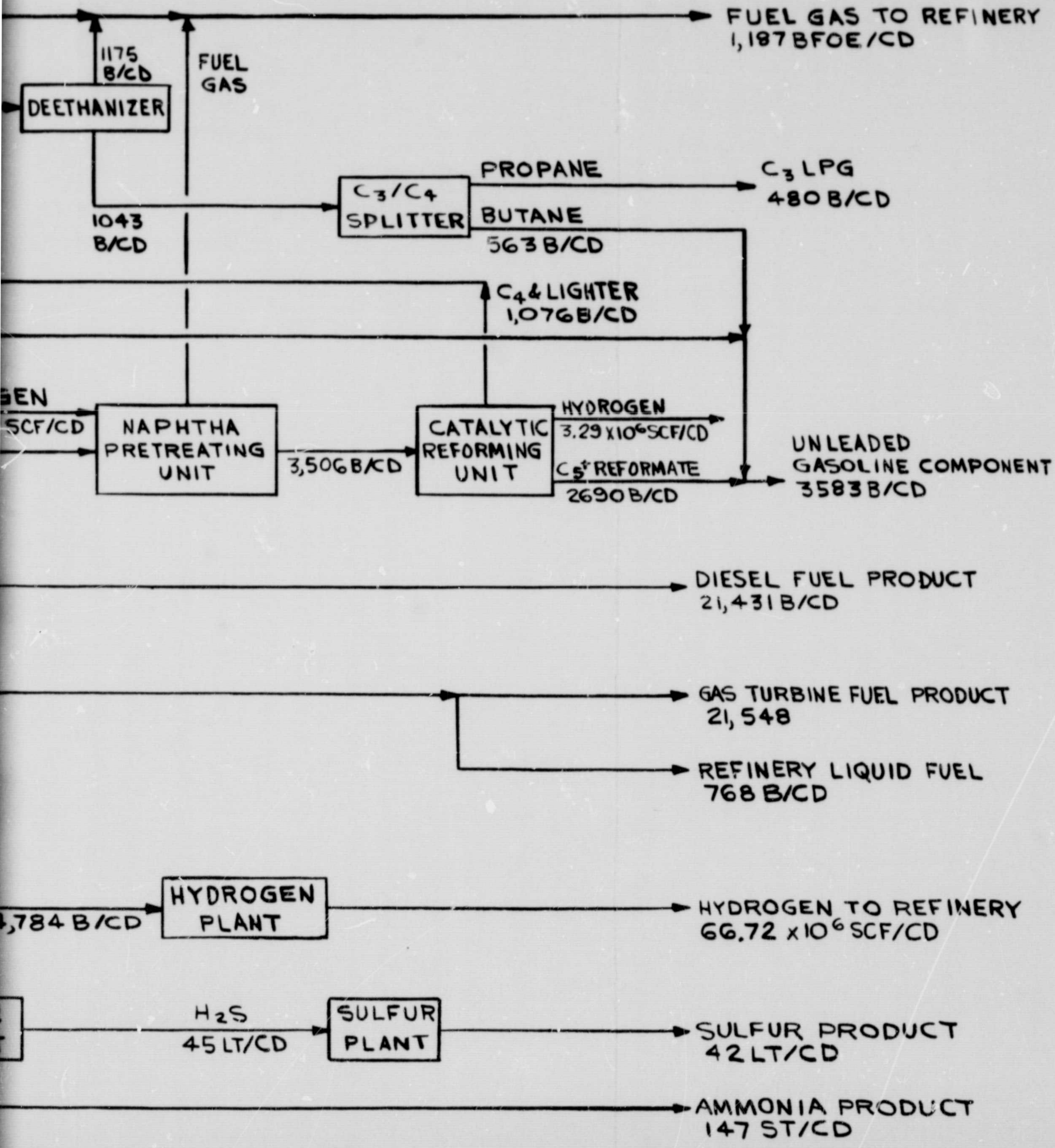
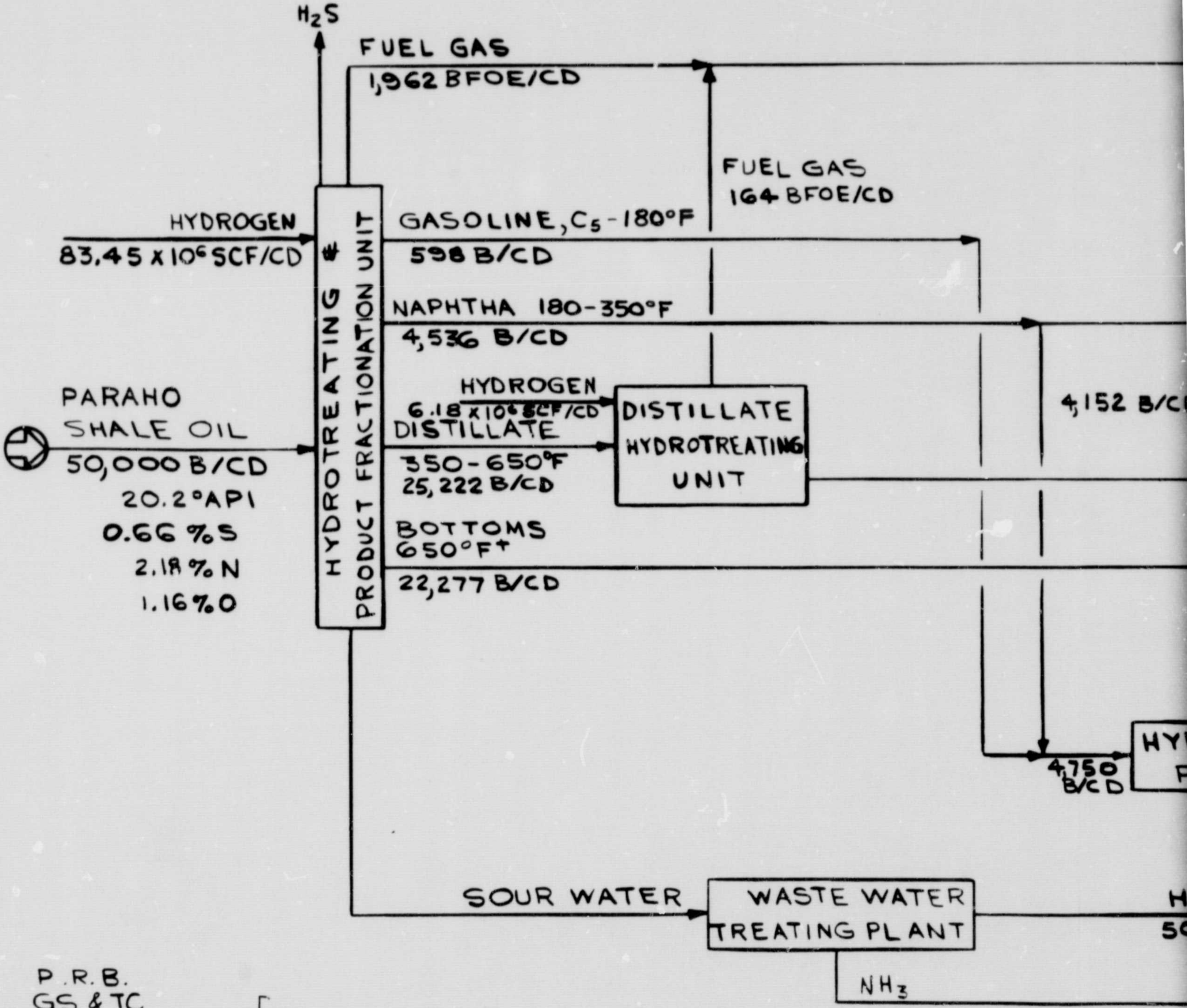


FIGURE IV-

UPGRADING OF SURFACE-RETORT

CASE 3020: HYDROTREATING OF
DISTILLATE TO DIESEL FUEL; S



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IGURE IV-13

E-RETORTED SHALE OIL TO GAS TURBINE FUEL

REATING OF PARAHO SHALE OIL AT INTERMEDIATE SEVERITY;
SEL FUEL; STEAM REFORMING H_2 PLANT

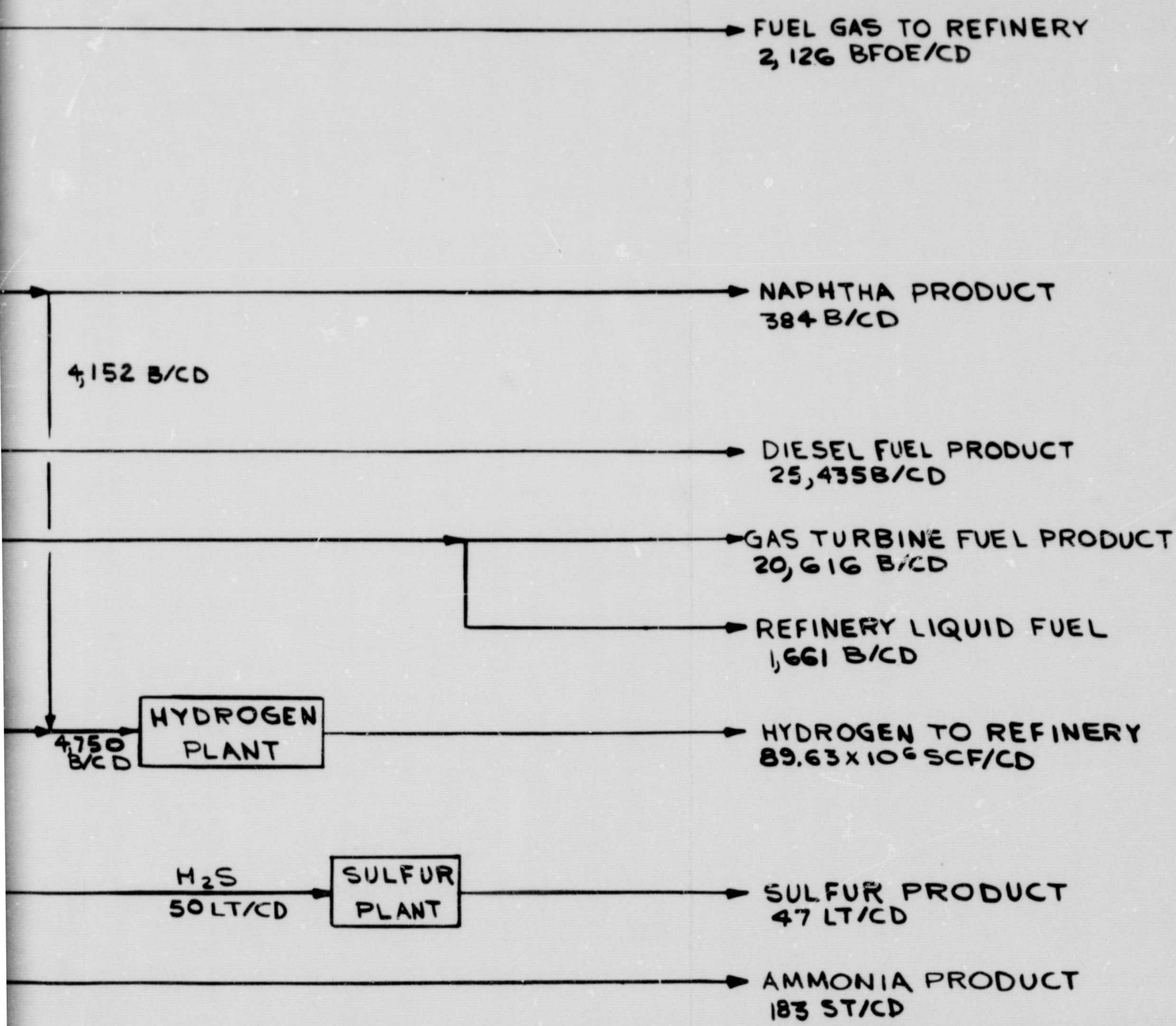

FIGURE IV-

UPGRADING OF SURFACE-RETOR

CASE 3030: HYDROTREATING O
DISTILLATE TO DIESEL FUEL;

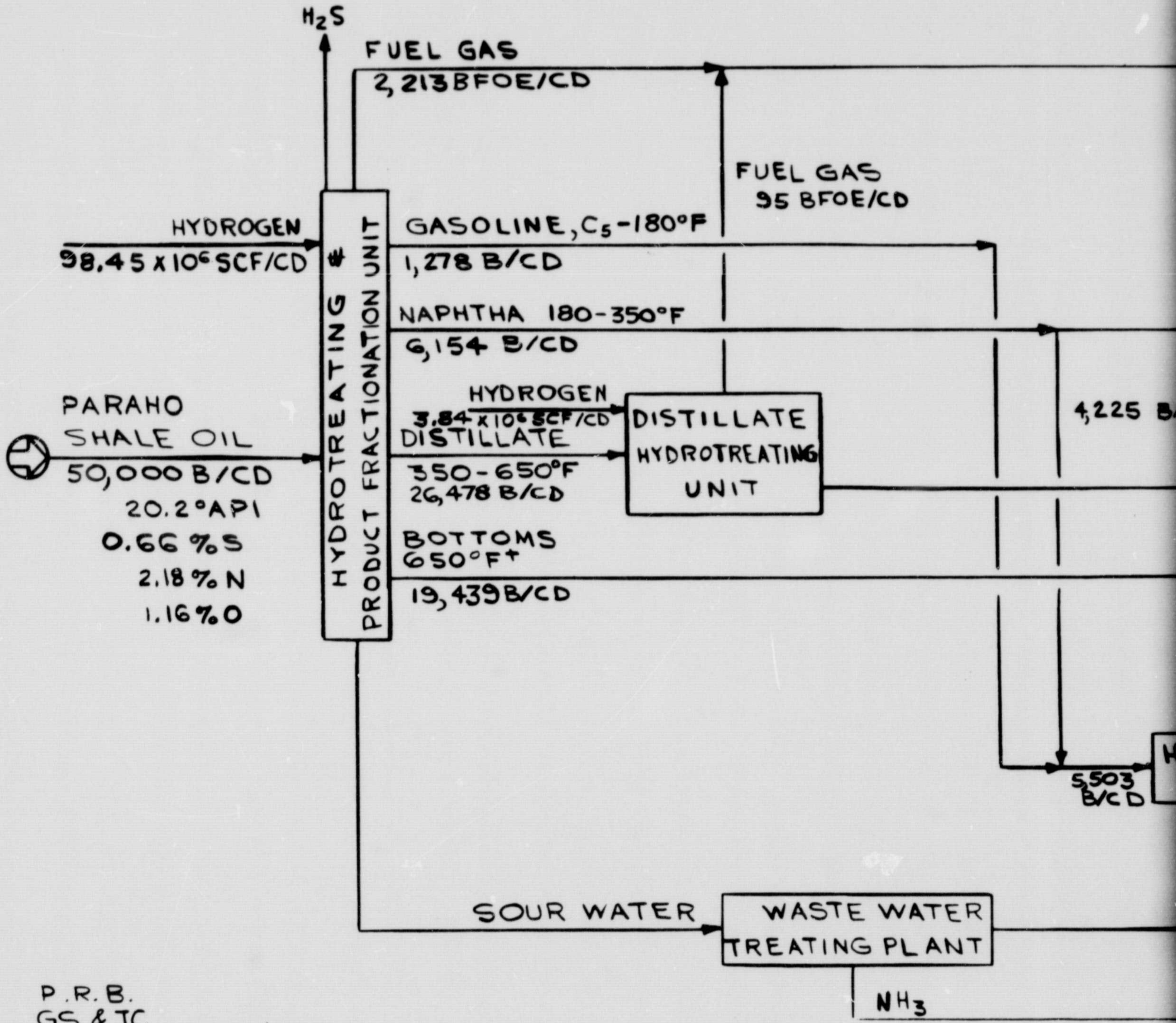

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FIGURE IV-14
CE-RETORTED SHALE OIL TO GAS TURBINE FUEL

TREATING OF PARAHO SHALE OIL AT HIGH SEVERITY;
SEL FUEL; STEAM REFORMING H_2 PLANT

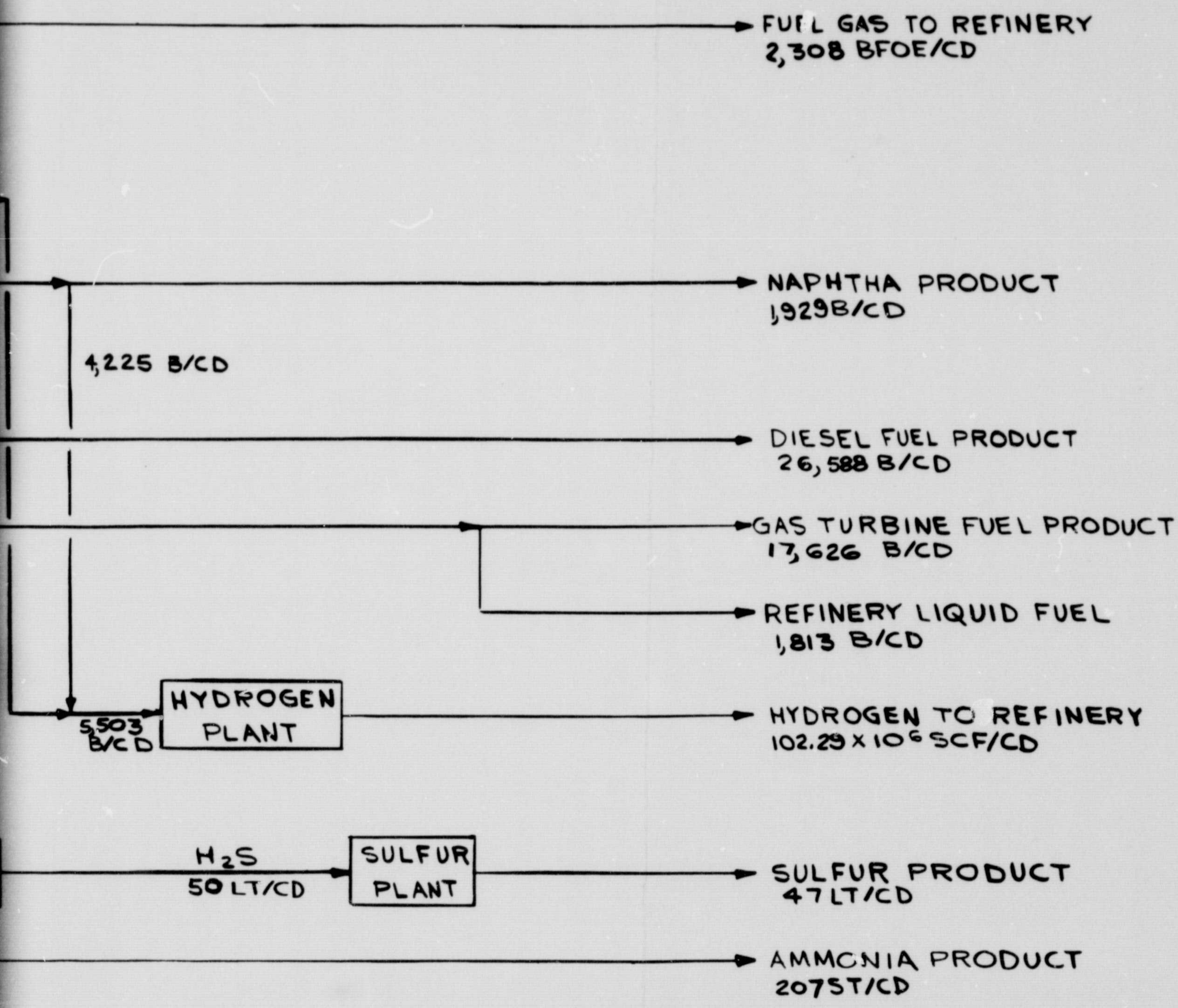

FIGURE IV-

UPGRADING OF SURFACE-RETORT

CASE 301A: HYDROTREATING OF
TOTAL 350°F+ TO GAS TURB

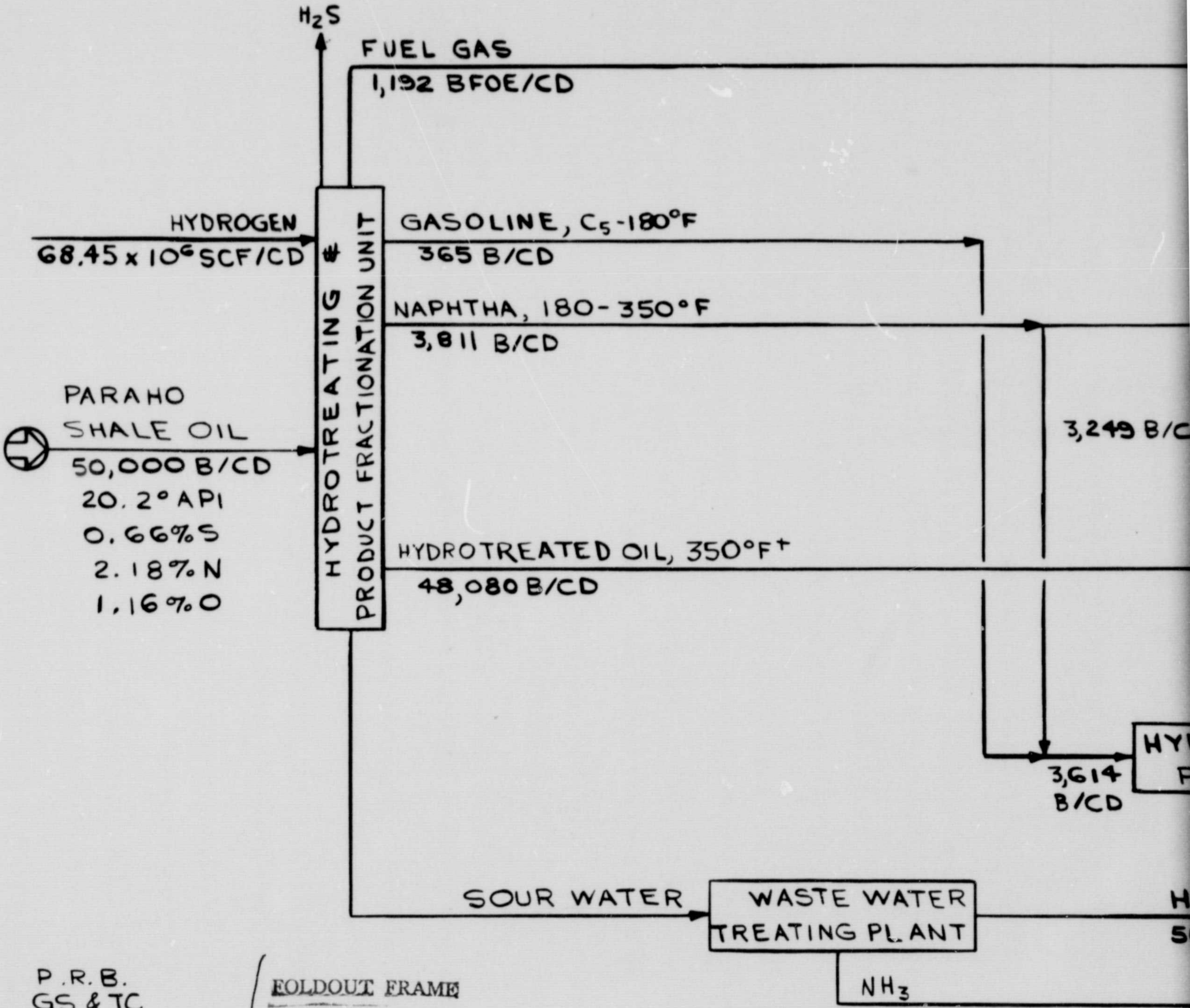

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FIGURE IV - 15

CE-RETORTED SHALE OIL TO GAS TURBINE FUEL

TREATING OF PARAHO SHALE OIL AT MODERATE SEVERITY;
TO GAS TURBINE FUEL

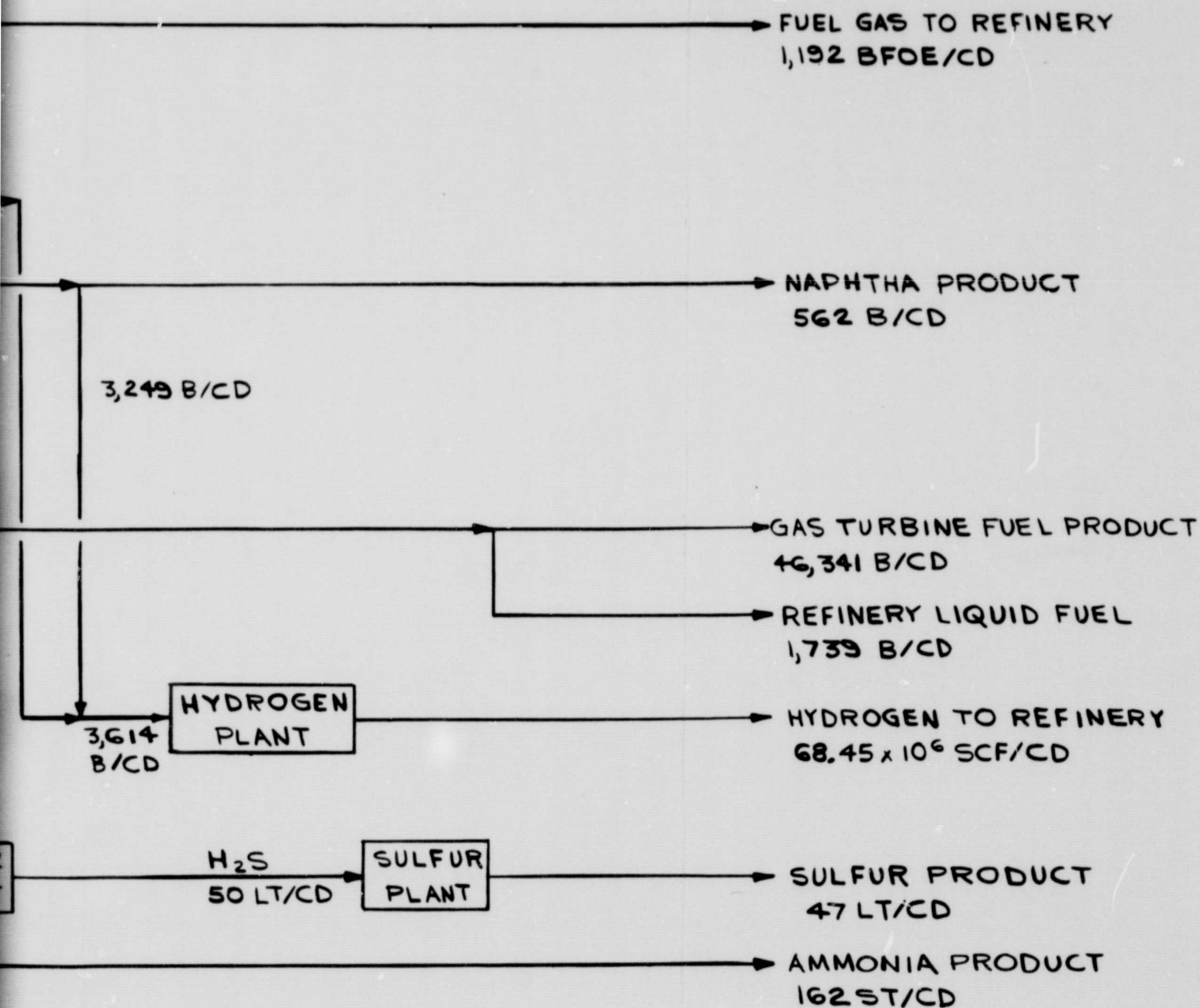
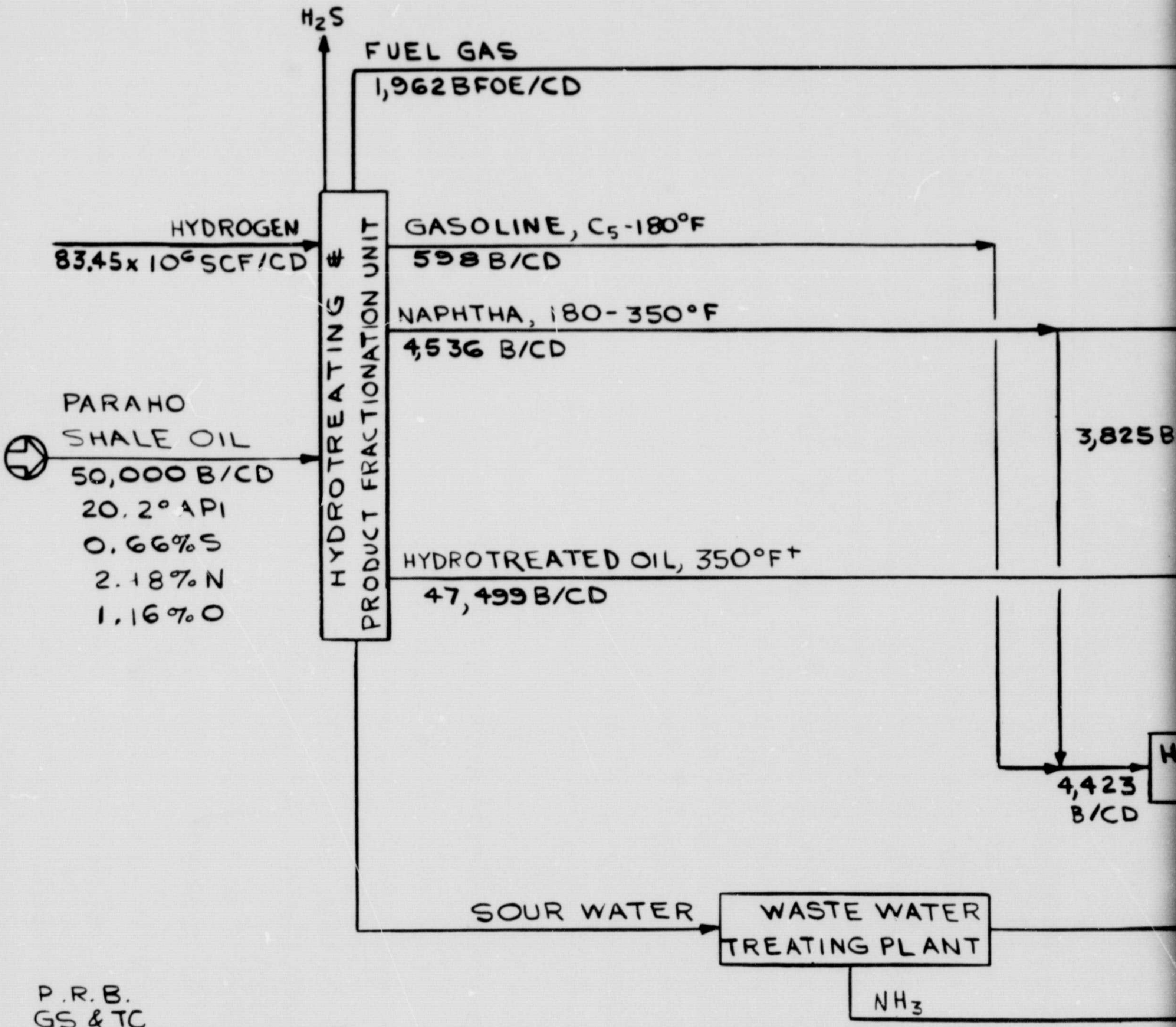


FIGURE IV-
UPGRADING OF SURFACE-RETORT

CASE 302A: HYDROTREATING O
TOTAL 350°F+ TO GAS TUR



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IGURE IV-16
E-RETORTED SHALE OIL TO GAS TURBINE FUEL

REATING OF PARAHO SHALE OIL AT INTERMEDIATE SEVERITY;
TO GAS TURBINE FUEL

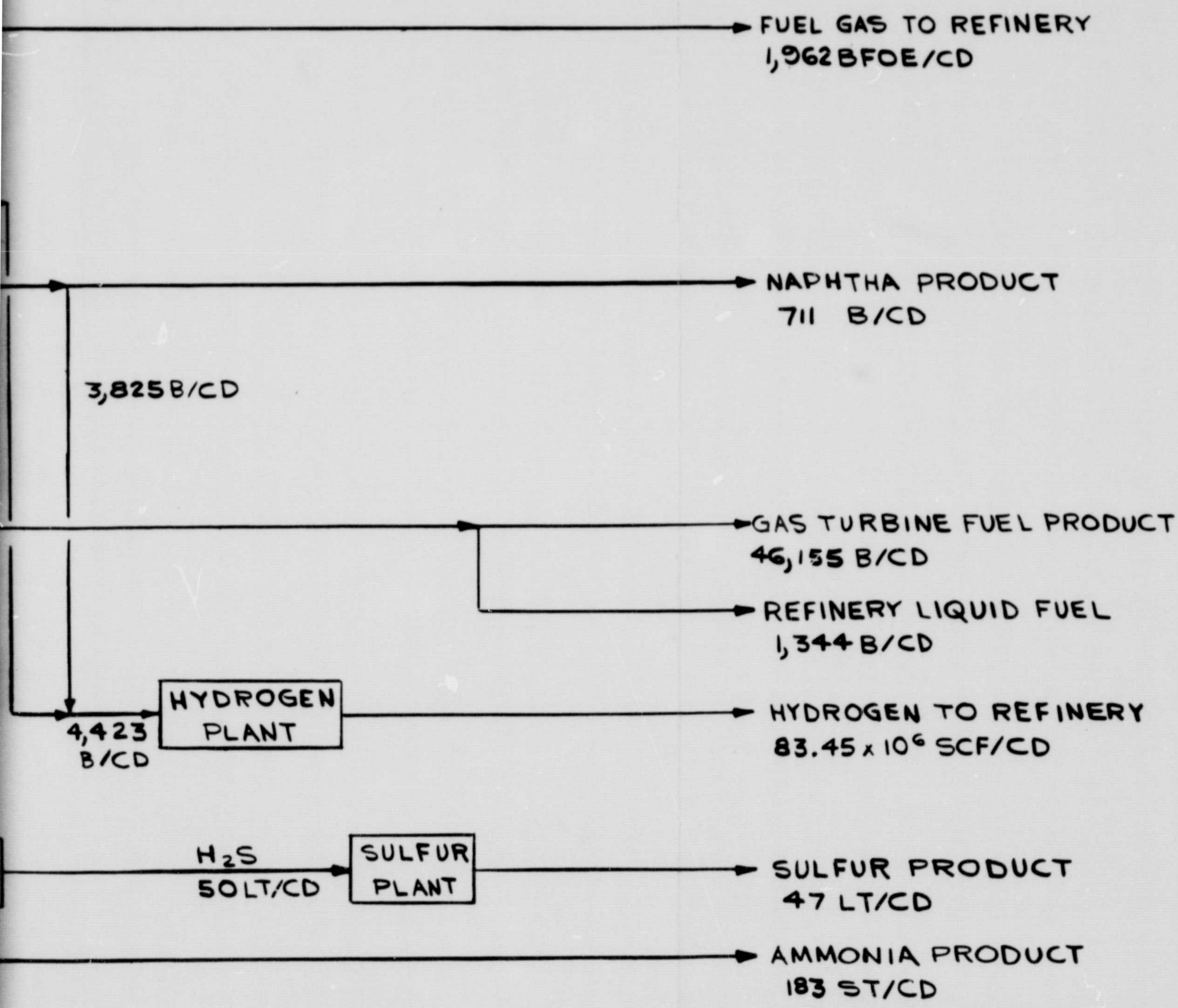
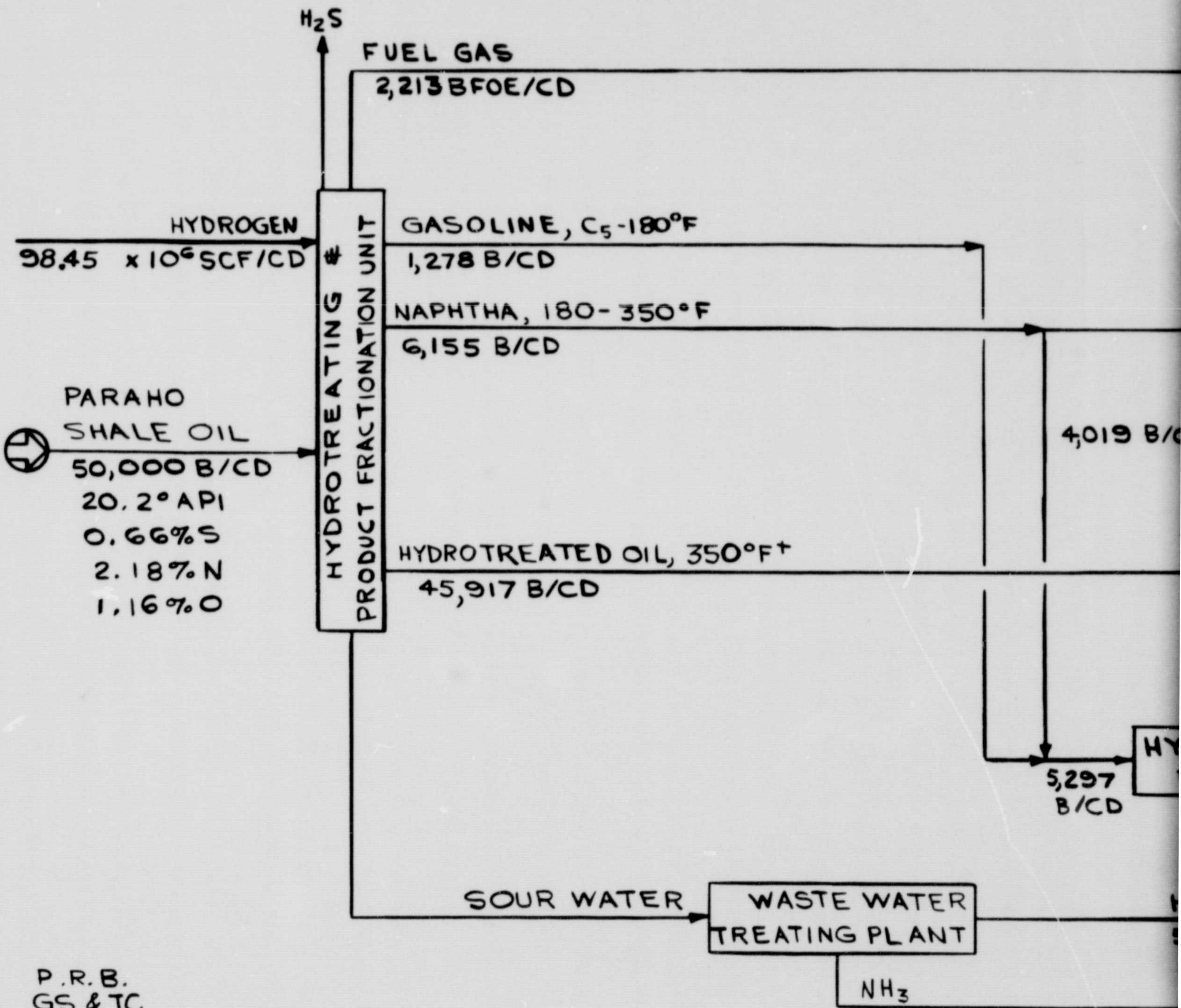


FIGURE IV-

UPGRADING OF SURFACE-RETORT

CASE 303A : HYDROTREATING OF

TOTAL 350°F+ TO GAS TURI



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URE IV-17
-RETORTED SHALE OIL TO GAS TURBINE FUEL

EATING OF PARAHO SHALE OIL AT HIGH SEVERITY;
GAS TURBINE FUEL

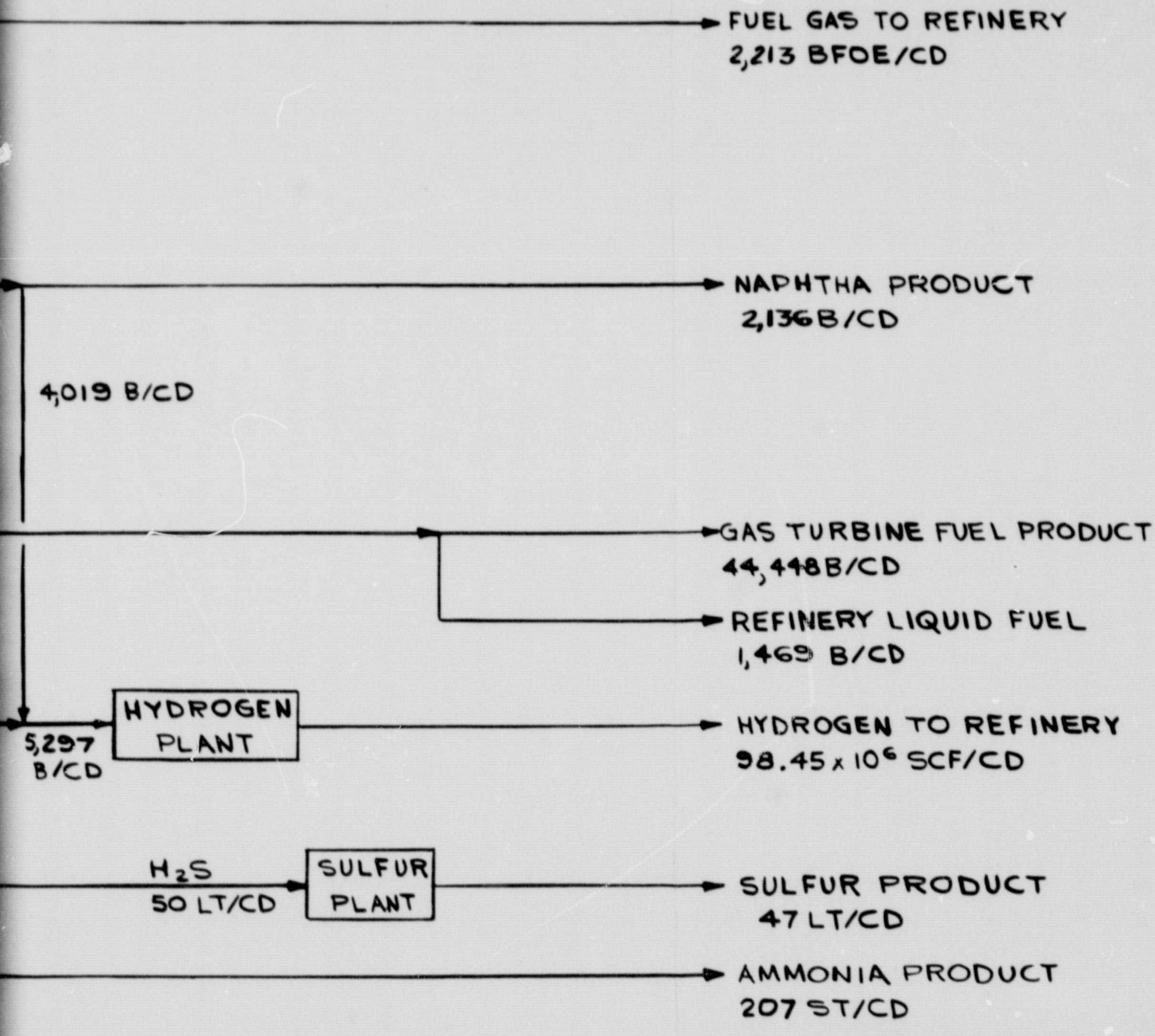
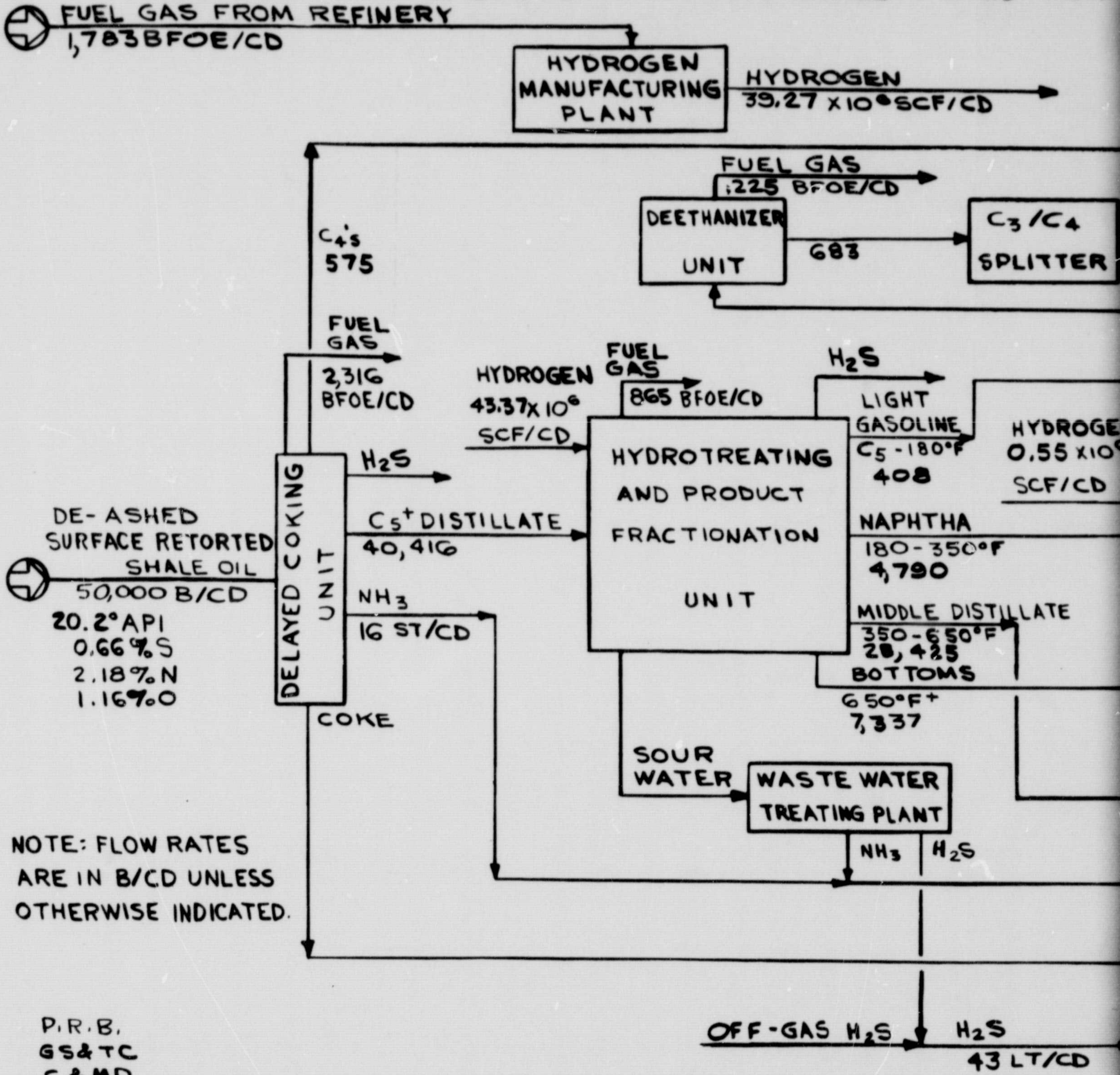


FIGURE IV - 18

UPGRADING OF SURFACE-RETORTED SHA

CASE 3040: DELAYED COKING OF PARAHO SHALE OIL AND HYDRO



NOTE: FLOW RATES ARE IN B/CD UNLESS OTHERWISE INDICATED.

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GURE IV - 18

-RETORTED SHALE OIL TO GAS TURBINE FUEL

OIL AND HYDROTREATING OF COKER DISTILLATE AT MODERATE SEVERITY

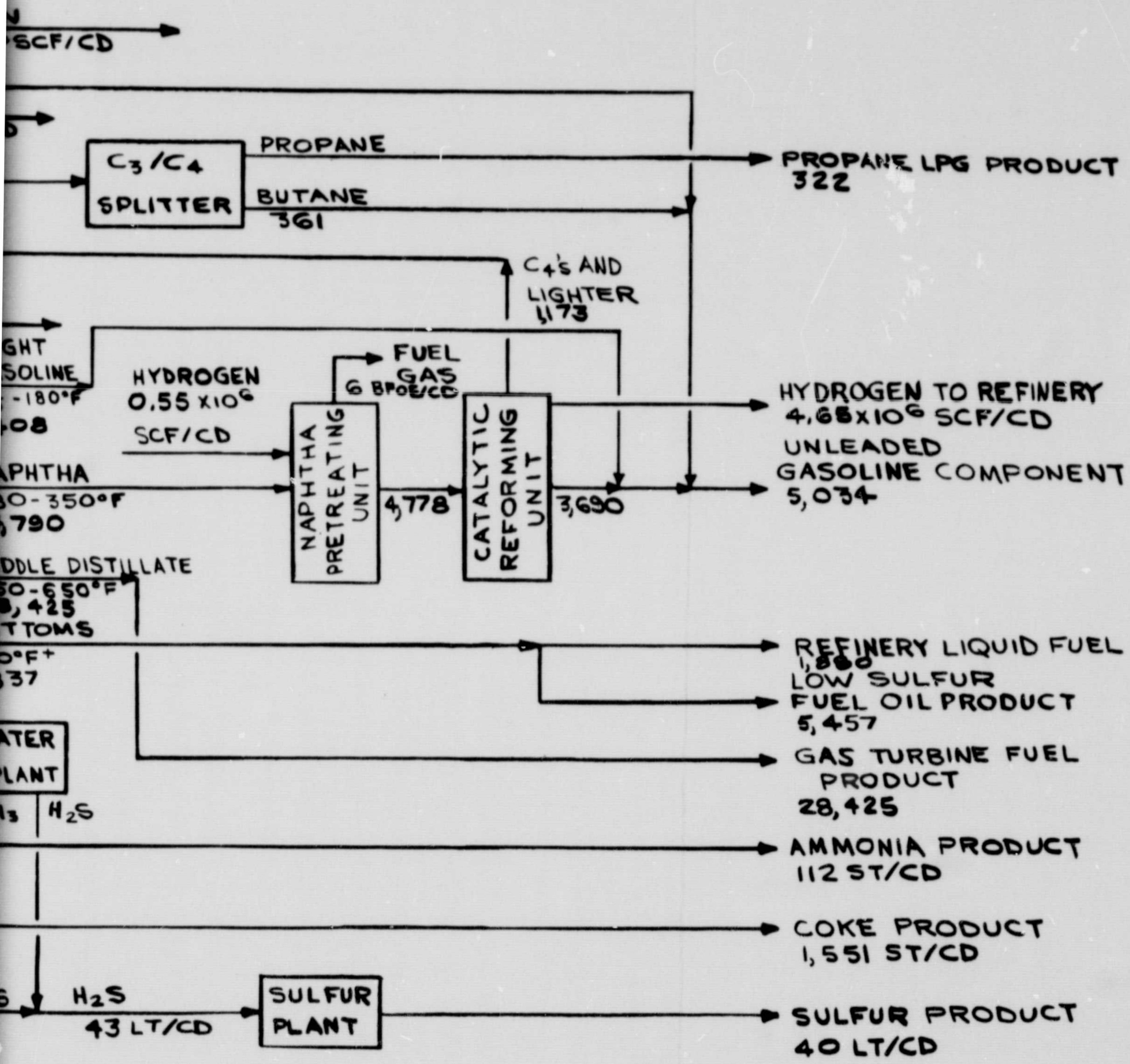

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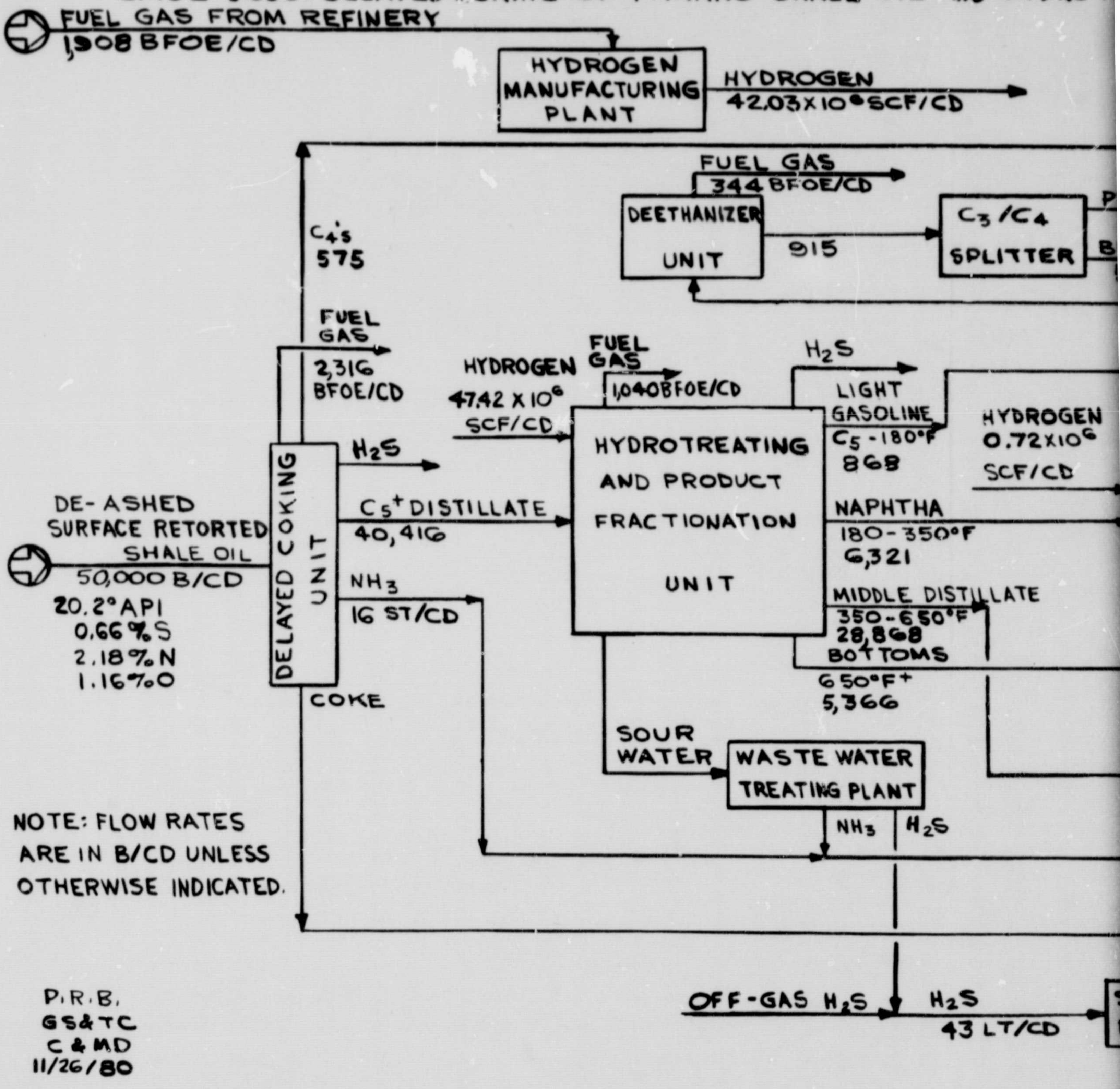
FIGURE IV - 19

UPGRADING OF SURFACE-RETORTED SHALE

CASE 3050: DELAYED COKING OF PARAHO SHALE OIL AND HYDROT



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SURE IV - 19

RETORTED SHALE OIL TO GAS TURBINE FUEL

OIL AND HYDROTREATING OF COKER DISTILLATE AT INTERMEDIATE SEVERITY

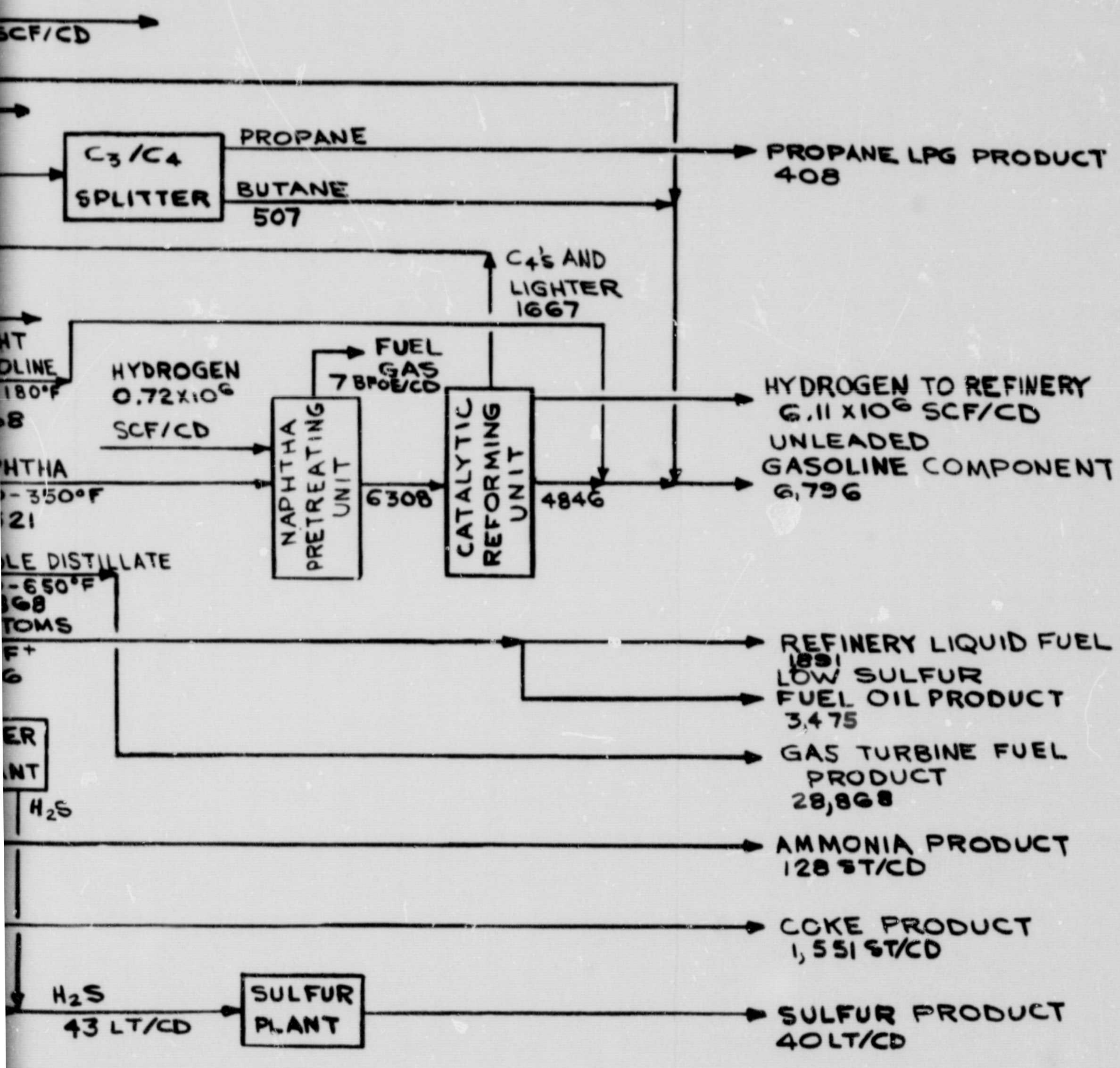

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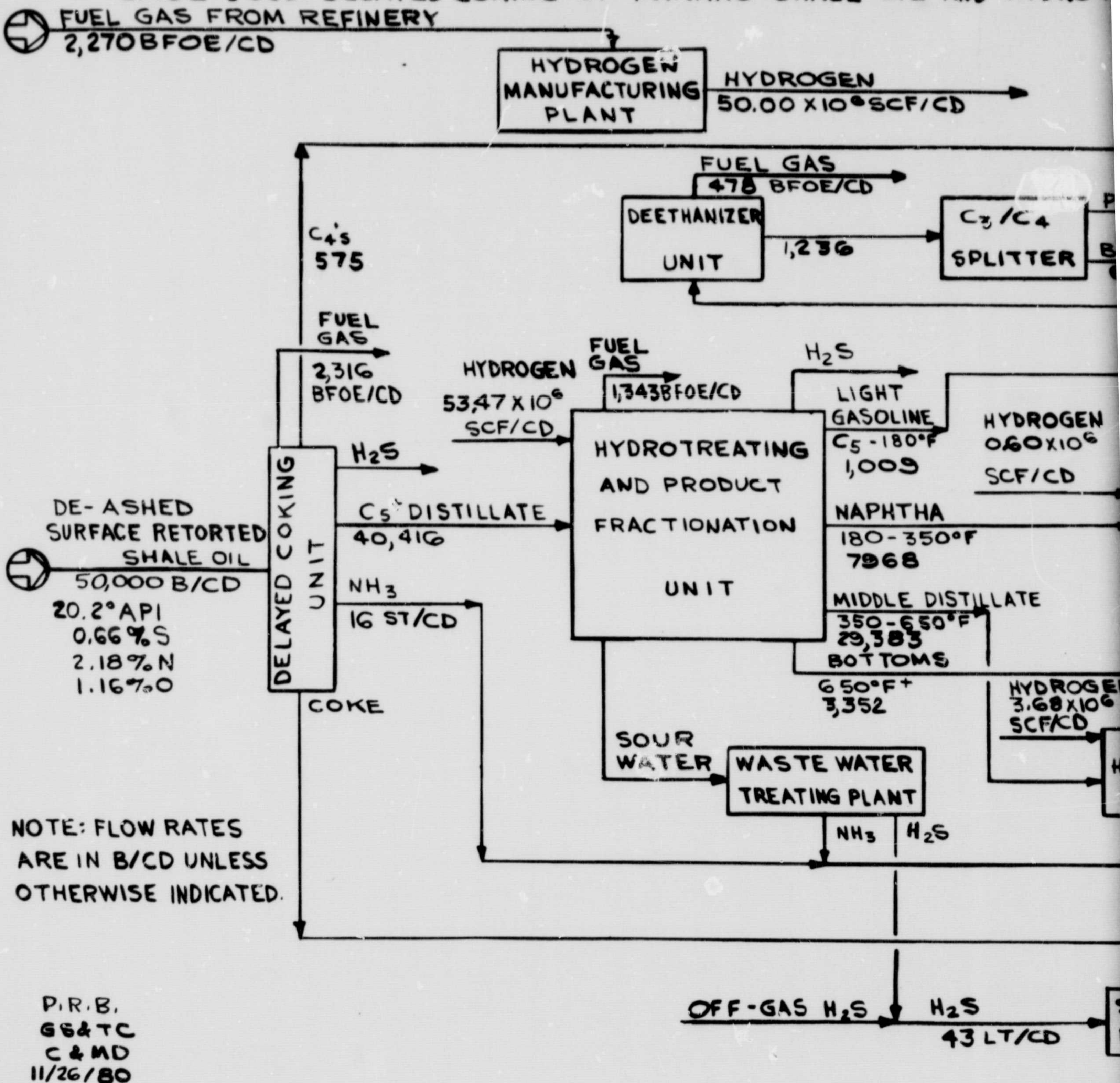
FIGURE IV - 20

UPGRADING OF SURFACE-RETORTED SHALE

CASE 3060: DELAYED COKING OF PARAHO SHALE OIL AND HYDROT



NOTE: FLOW RATES ARE IN B/CD UNLESS OTHERWISE INDICATED.

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RE IV - 20

ETORTED SHALE OIL TO GAS TURBINE FUEL

L AND HYDROTREATING OF COKER DISTILLATE AT HIGH SEVERITY

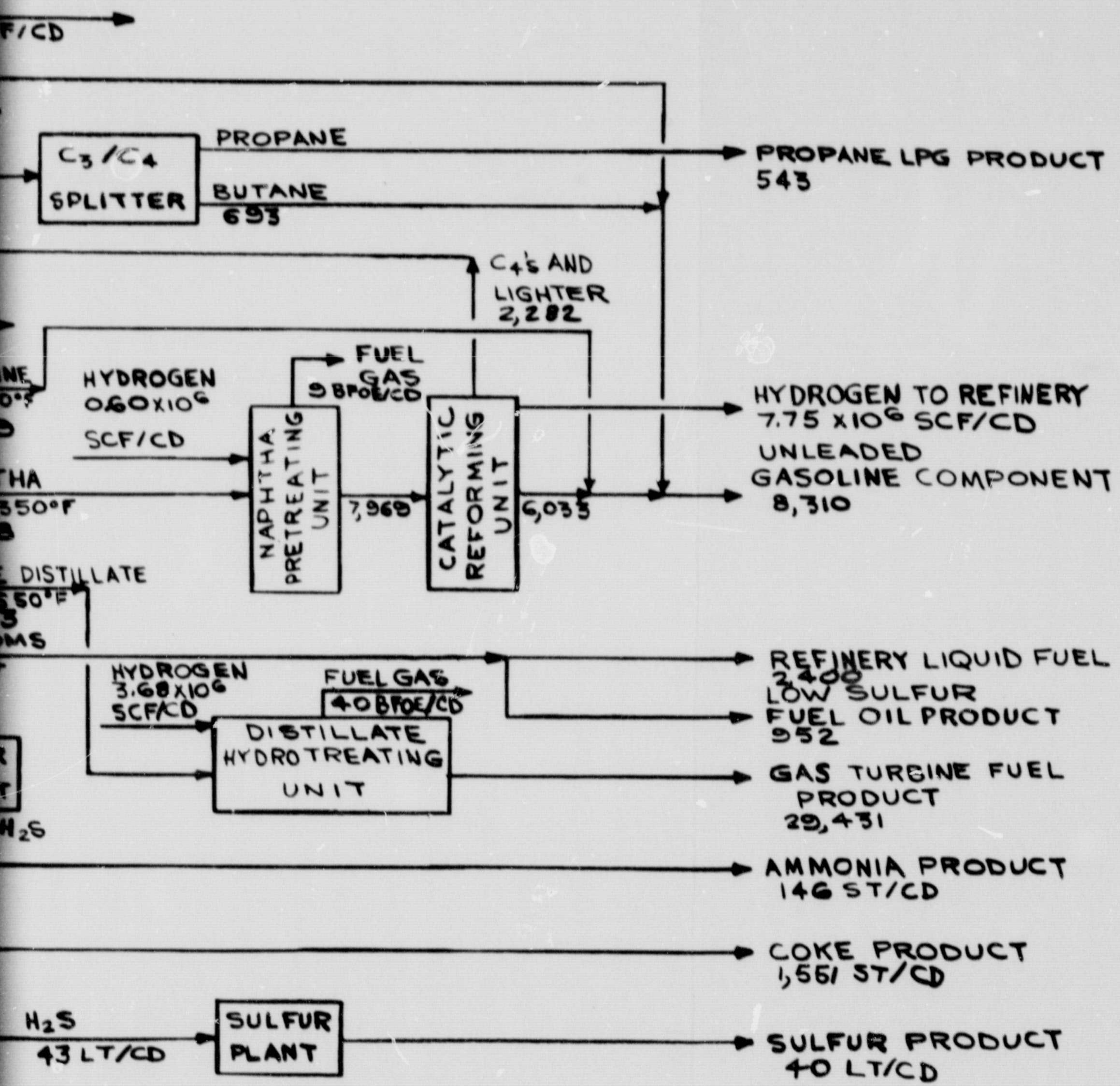

FIGURE IV- 2

UPGRADING OF MODIFIED IN-SITU

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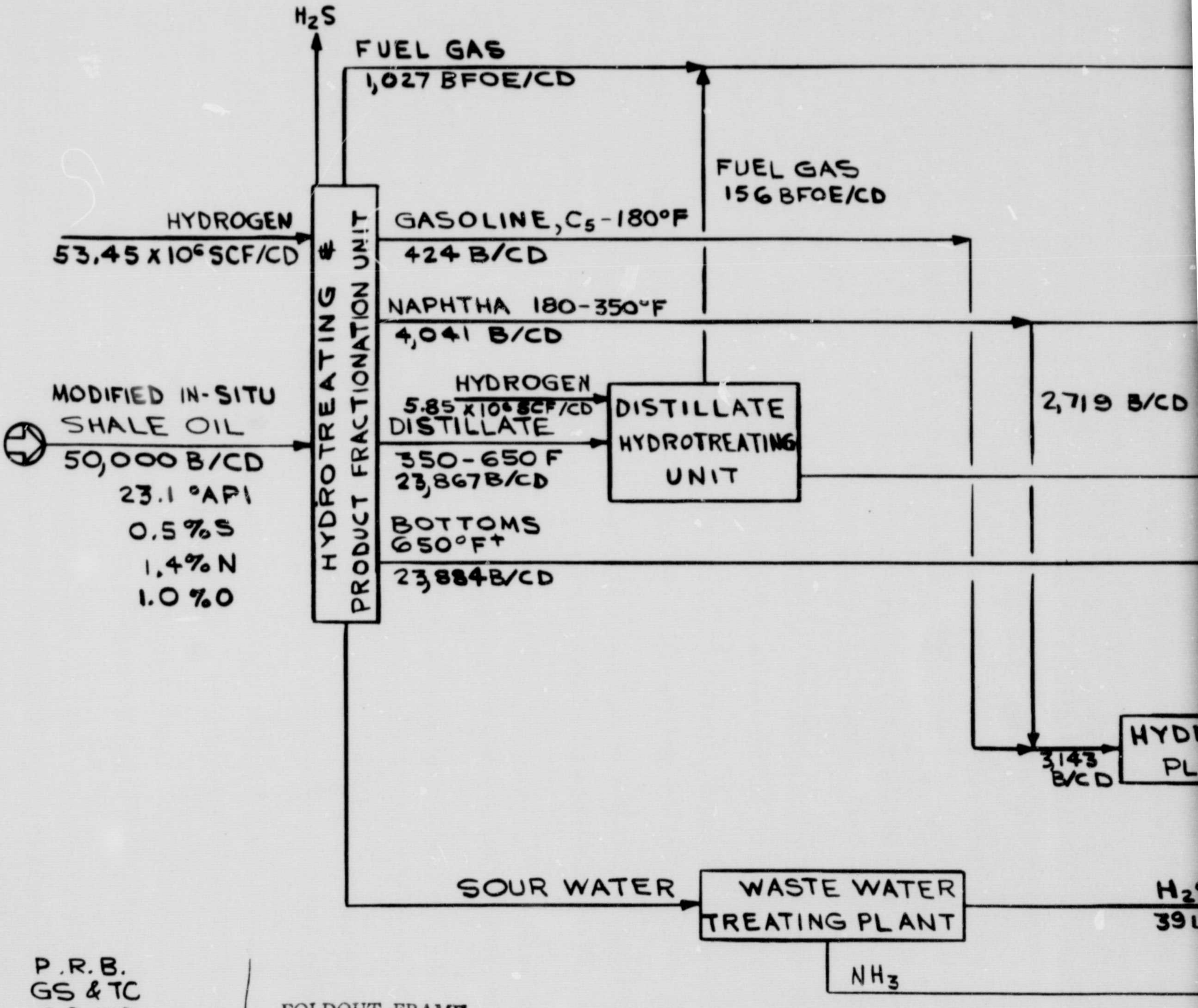
CASE 4020: HYDROTREATING OF M
DISTILLATE TO DIESEL FUEL



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GURE IV- 21

D IN-SITU SHALE OIL TO GAS TURBINE FUEL

REATING OF MIS SHALE OIL AT INTERMEDIATE SEVERITY;
EL FUEL

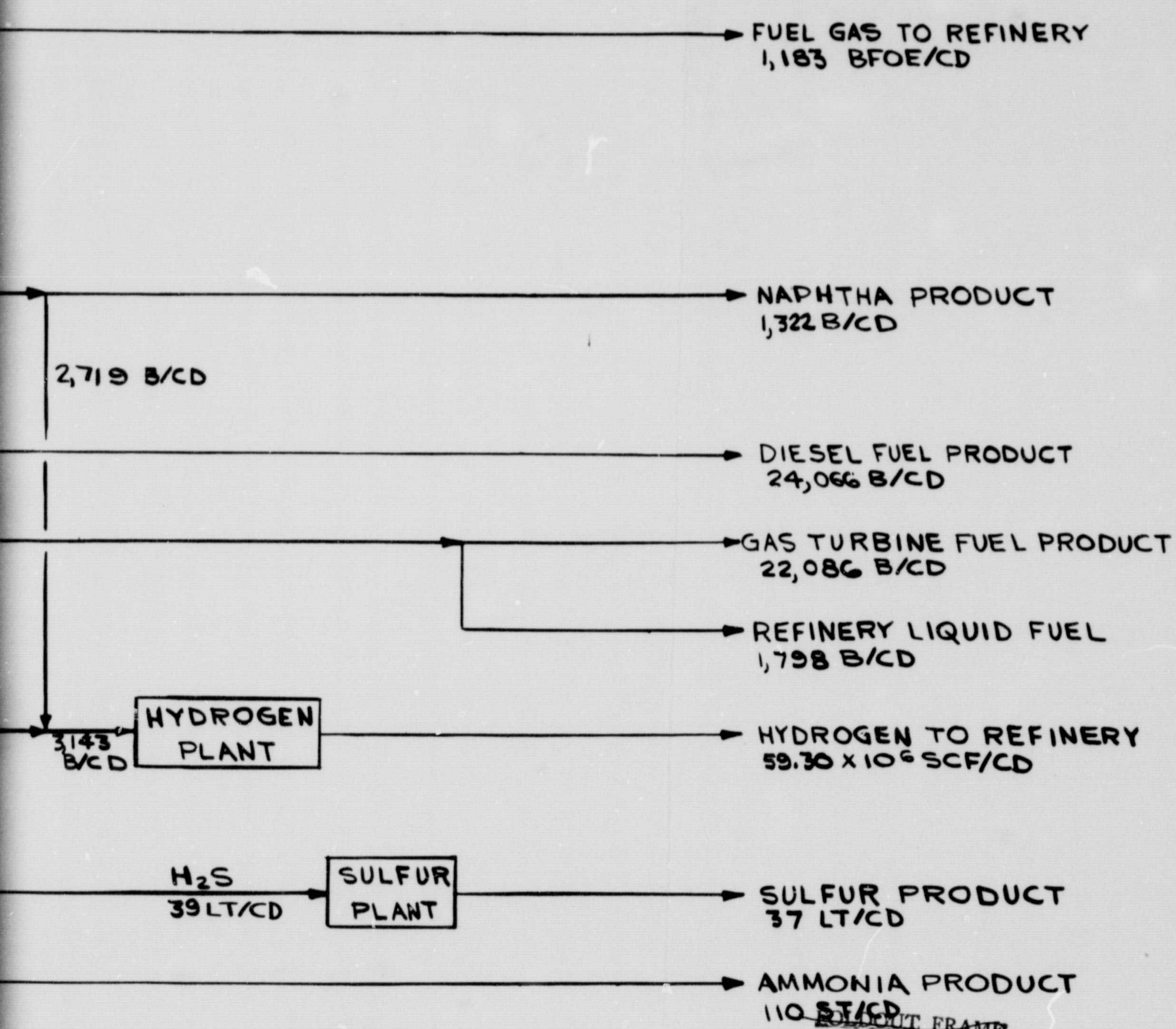

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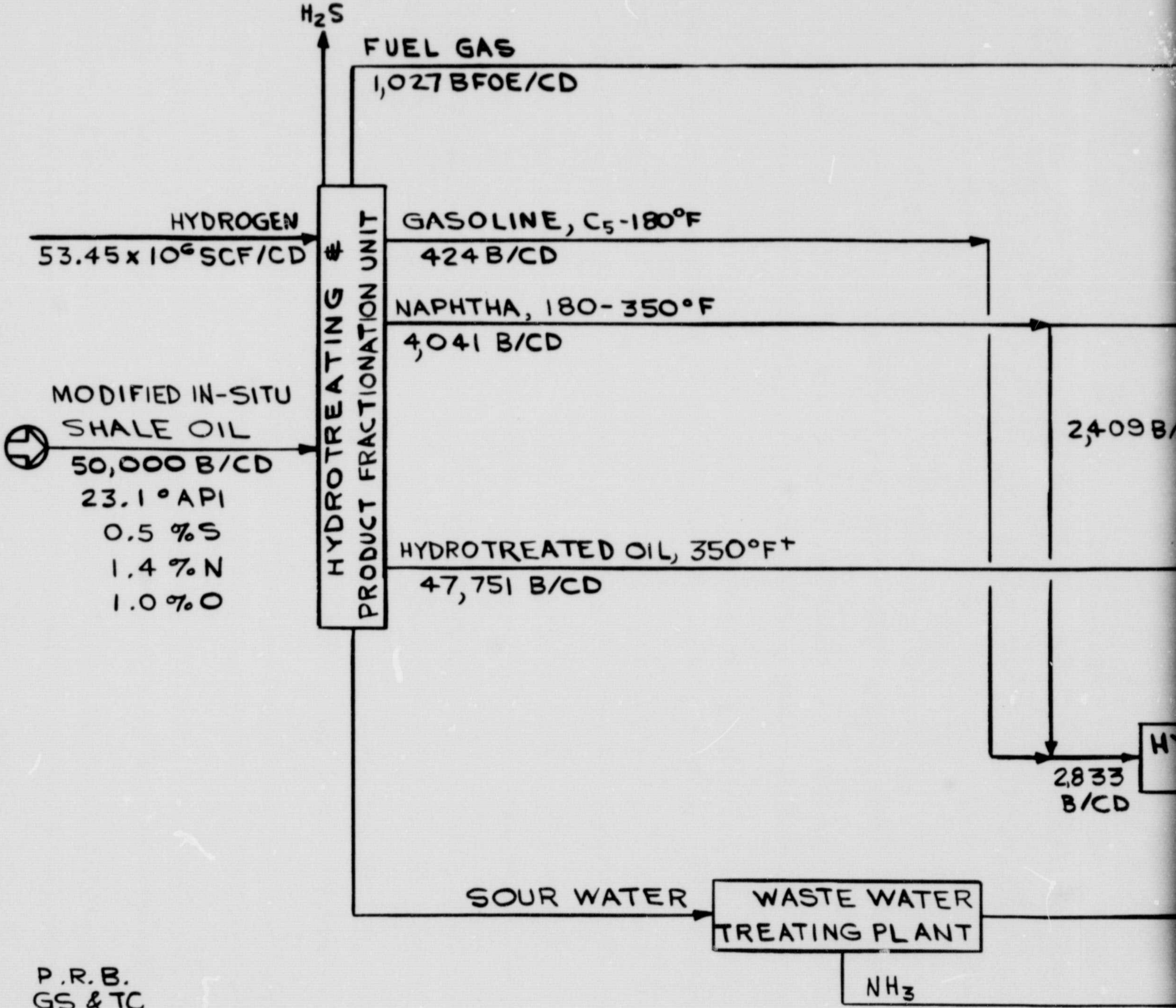
FIGURE IV-

UPGRADING OF MODIFIED IN-SITU

CASE 402A: HYDROTREATING O

TOTAL 350°F+ TO GAS TUR



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IGURE IV - 22
D IN-SITU SHALE OIL TO GAS TURBINE FUEL

REATING OF MIS SHALE OIL AT INTERMEDIATE SEVERITY;
O GAS TURBINE FUEL

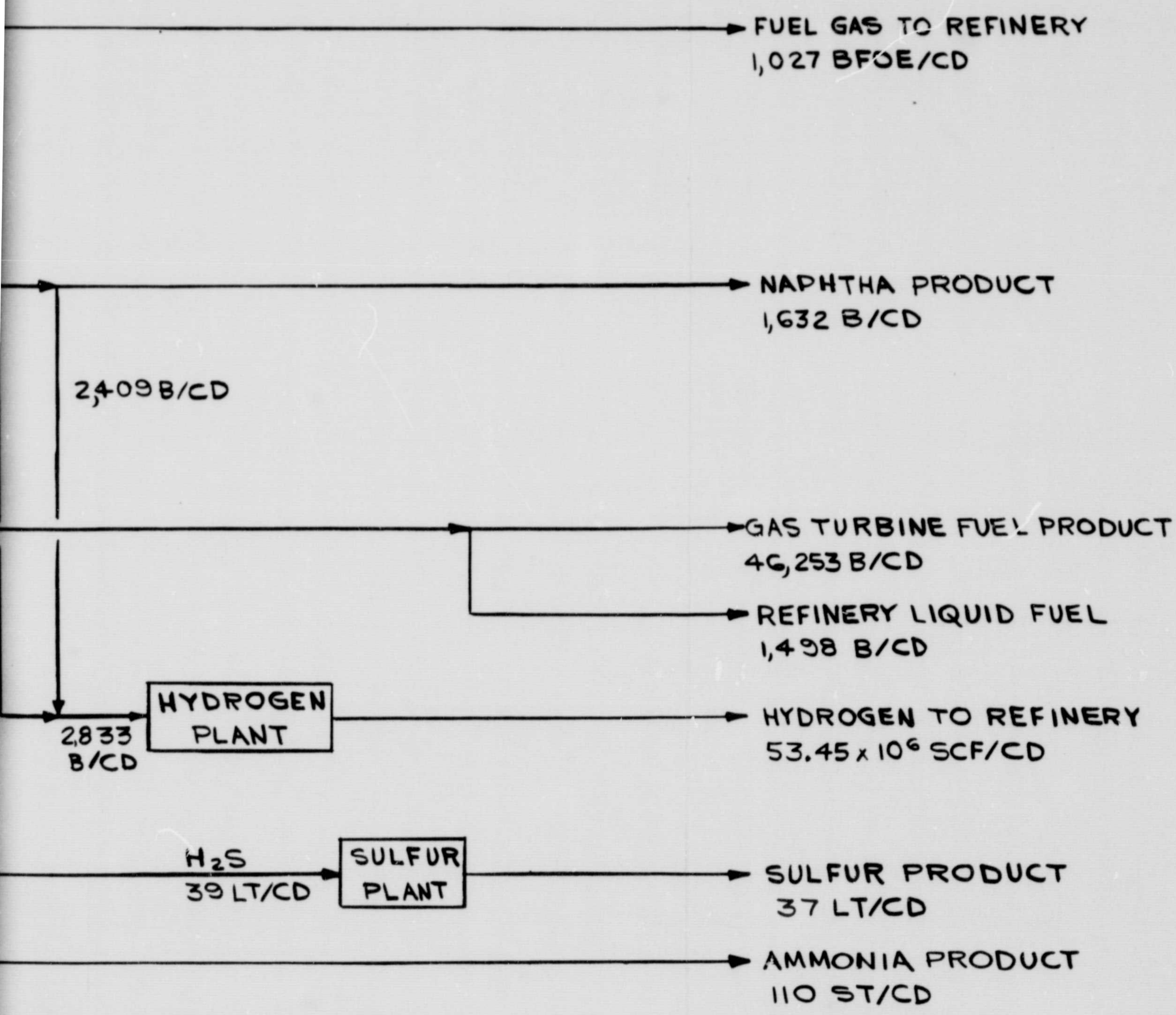

FIGURE IV-23

UPGRADING OF LOW-SULFUR PETROLEUM RESIDUAL OIL TO GAS TURBINE FUEL

CASE 5010: HYDROTREATING OF VACUUM BOTTOMS AT MODERATE SEVERITY

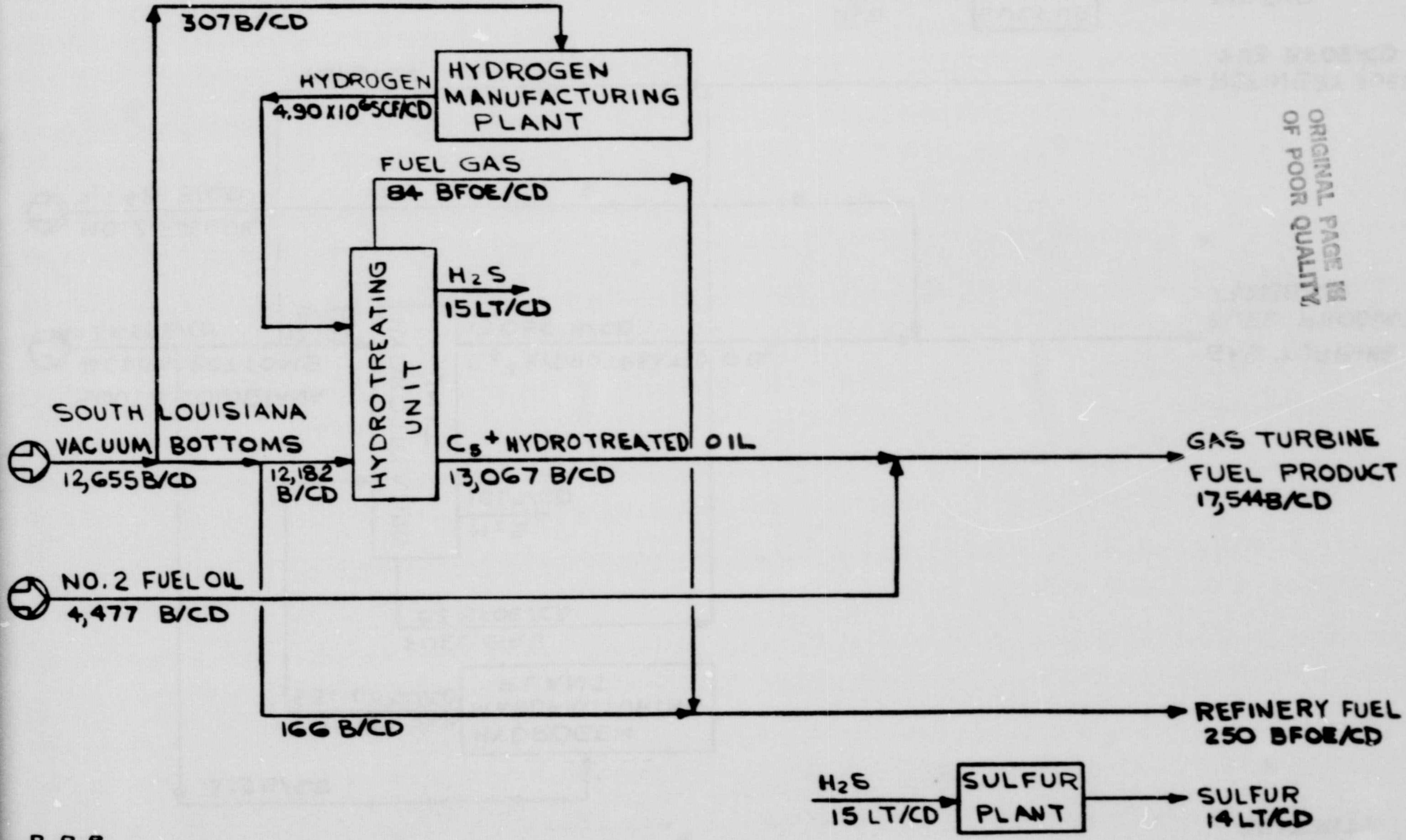

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FIGURE IV-24

UPGRADING OF LOW-SULFUR PETROLEUM RESIDUAL OIL TO GAS TURBINE FUEL

CASE 5020: HYDROTREATING OF VACUUM BOTTOMS AT INTERMEDIATE SEVERITY

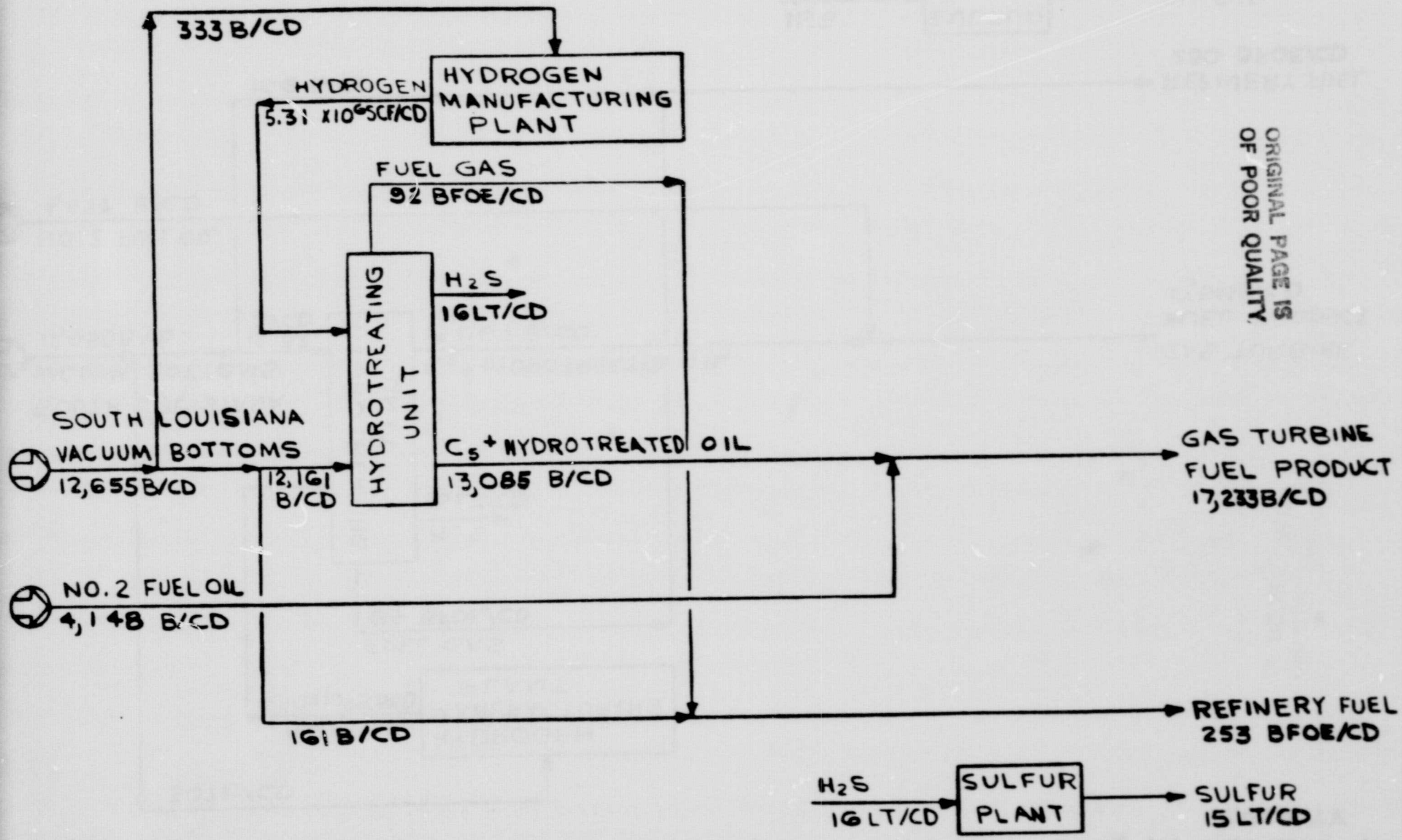

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FIGURE IV-25

UPGRADING OF LOW-SULFUR PETROLEUM RESIDUAL OIL TO GAS TURBINE FUEL
CASE 5030: HYDROTREATING OF VACUUM BOTTOMS AT HIGH SEVERITY

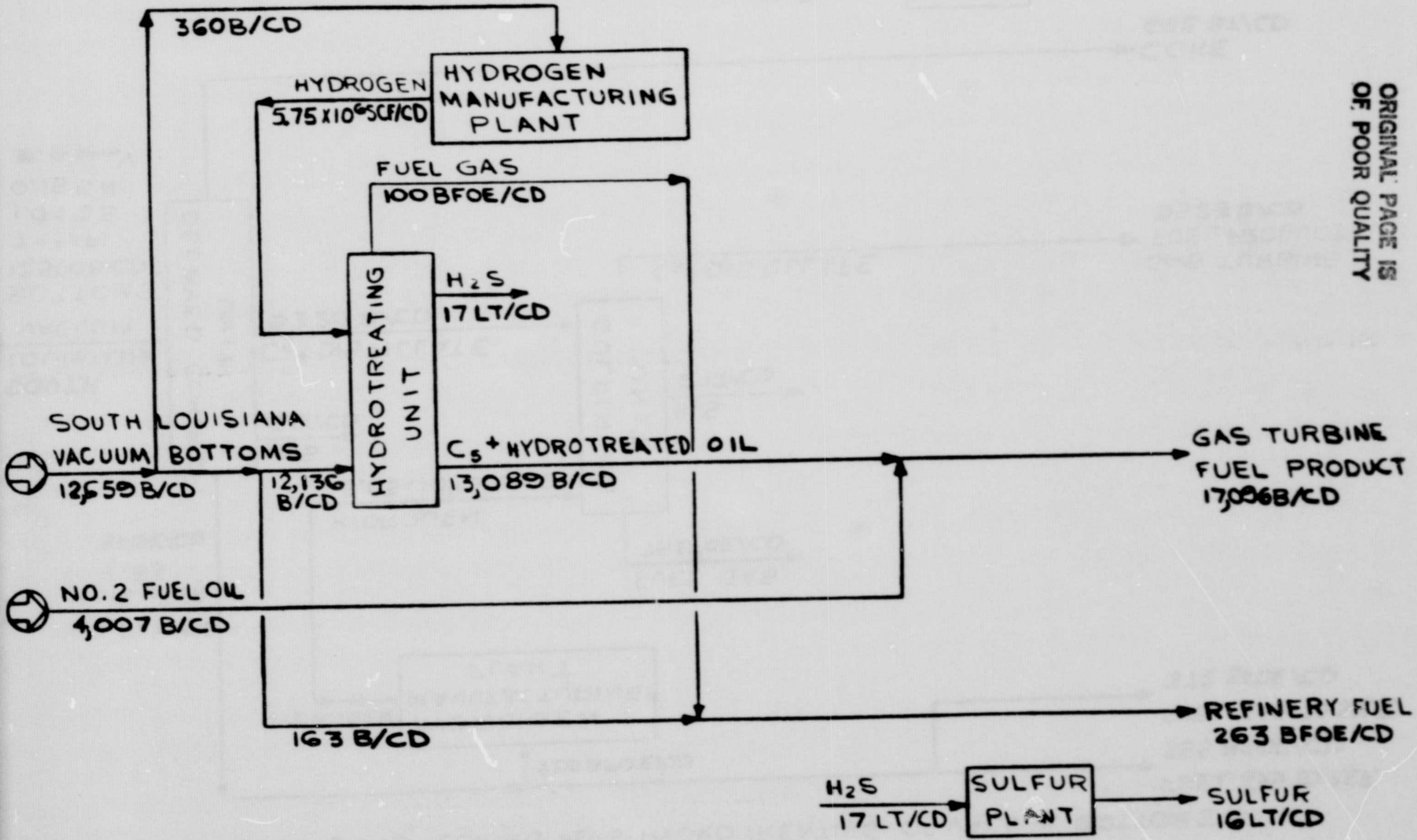

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FIGURE IV-26

UPGRADING OF LOW-SULFUR PETROLEUM RESIDUAL OIL TO GAS TURBINE FUEL

CASE 5040: COKING PLUS HYDROTREATING OF VACUUM BOTTOMS

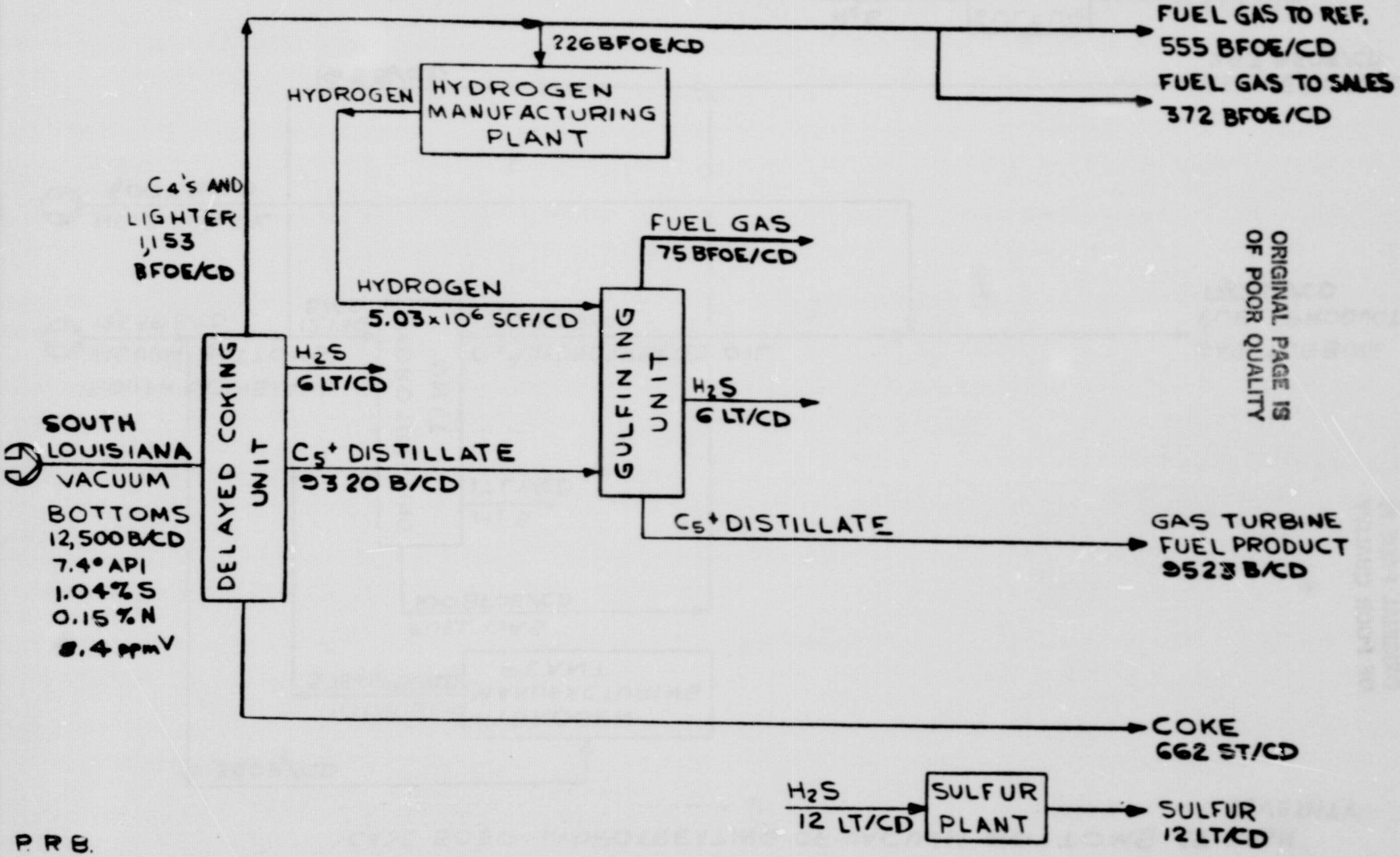

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FIGURE IV-27

UPGRADING OF HIGH-SULFUR PETROLEUM RESIDUAL OIL TO GAS TURBINE FUEL

CASE 6010: HYDROTREATING OF VACUUM BOTTOMS AT MODERATE SEVERITY

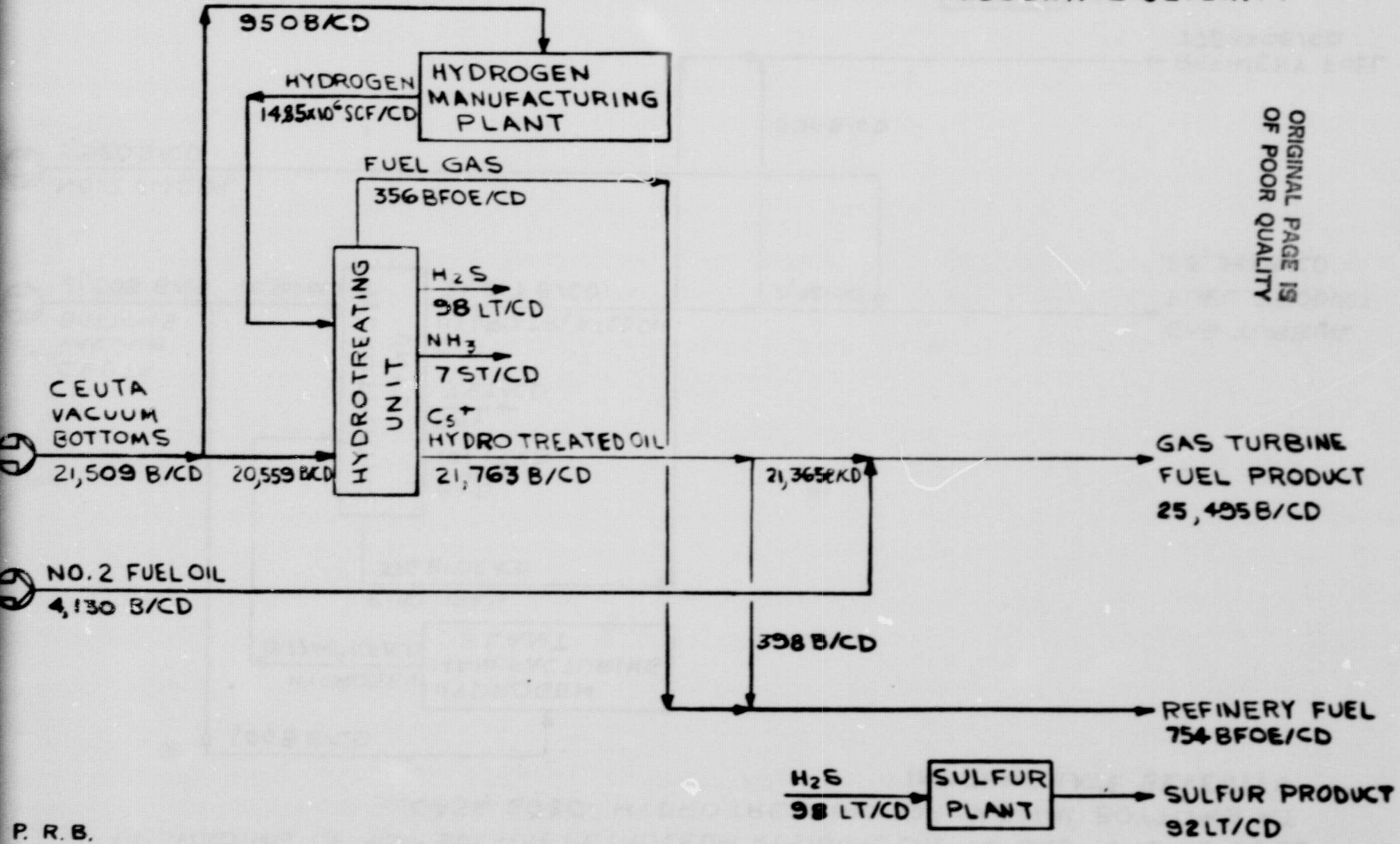

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FIGURE IV-28

UPGRADING OF HIGH-SULFUR PETROLEUM RESIDUAL OIL TO GAS TURBINE FUEL

CASE 6020: HYDROTREATING OF VACUUM BOTTOMS AT INTERMEDIATE SEVERITY

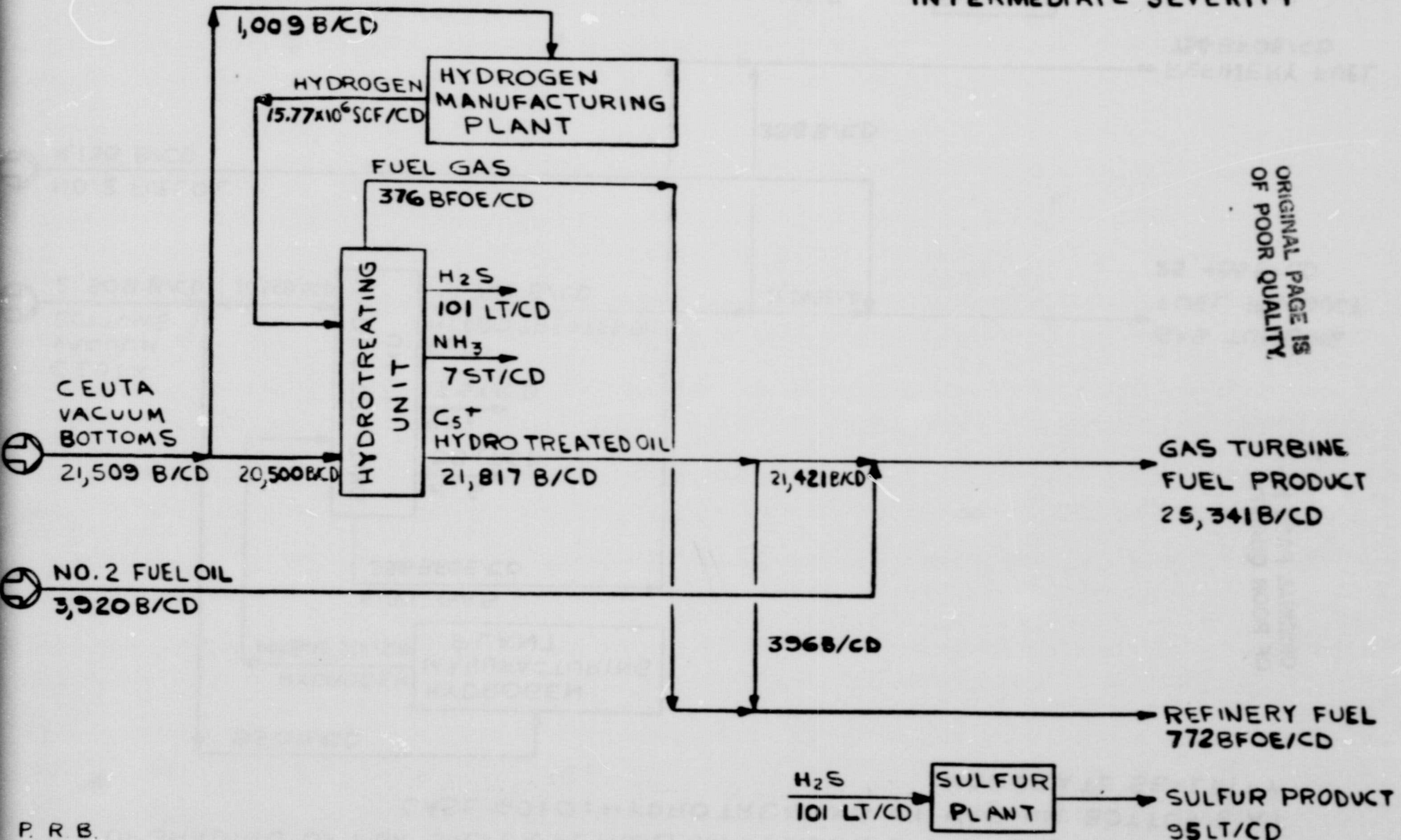

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FIGURE IV-29

UPGRADING OF HIGH-SULFUR PETROLEUM RESIDUAL OIL TO GAS TURBINE FUEL

CASE 6030: HYDROTREATING OF VACUUM BOTTOMS AT HIGH SEVERITY

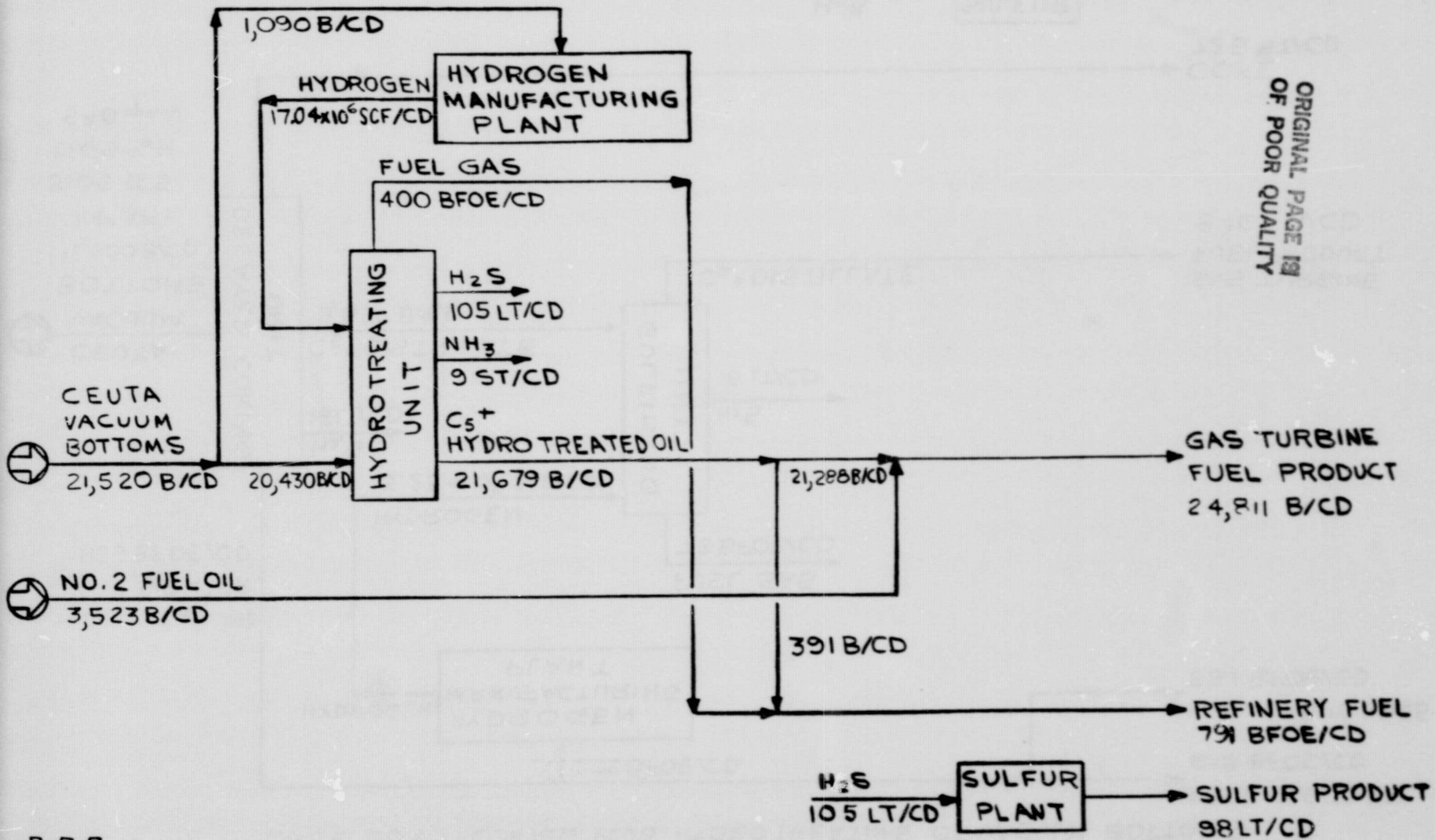

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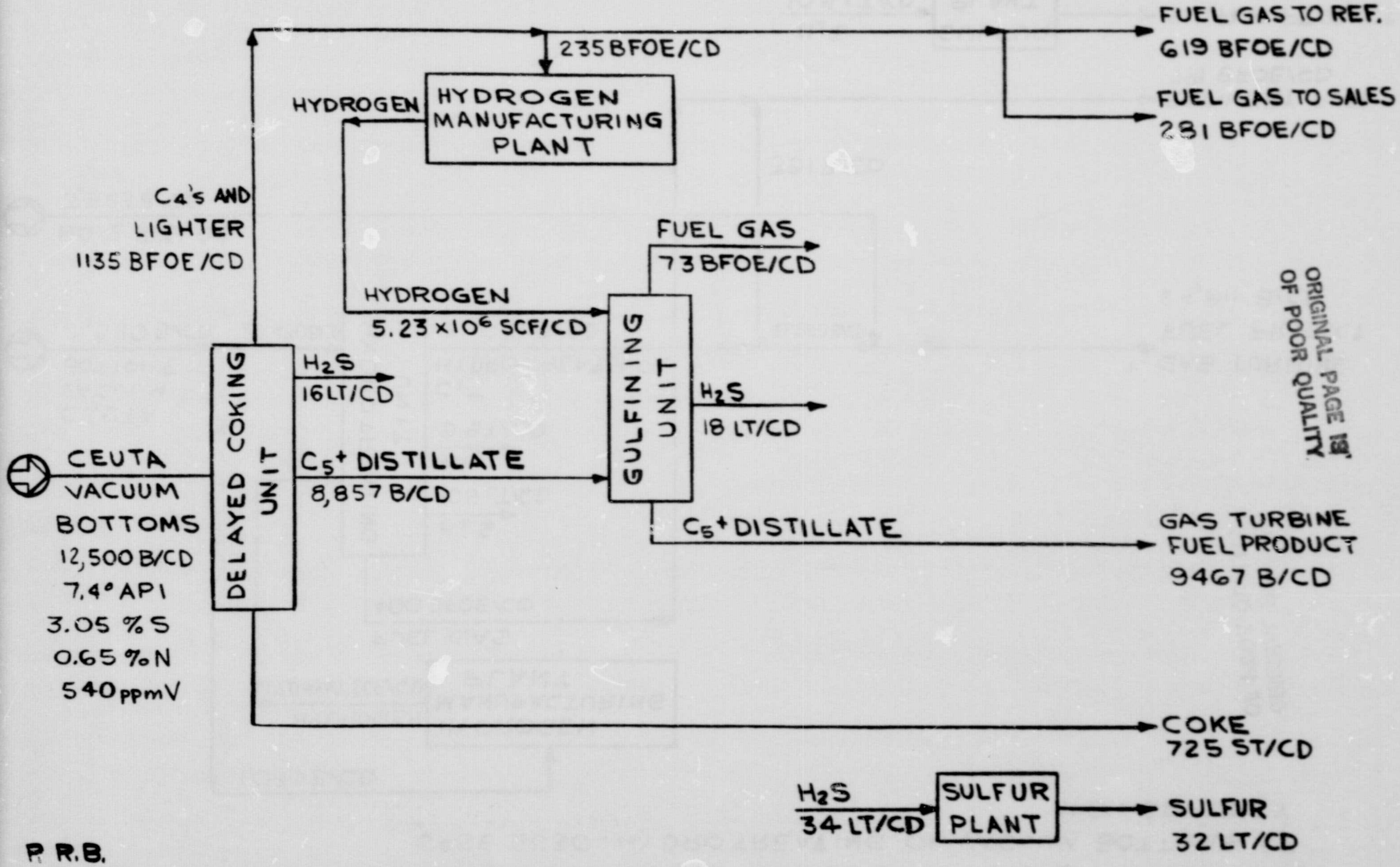
FIGURE IV - 30

UPGRADING OF HIGH-SULFUR PETROLEUM RESIDUAL OIL TO GAS TURBINE FUEL

CASE 6040: COKING PLUS HYDROTREATING OF VACUUM BOTTOMS



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APPENDIX B

ECONOMIC EVALUATION TABLES

Table III-A

GAS TURBINE FUEL QUALITY/PROCESSING STUDY

BASES FOR COST ESTIMATES

General

Processing costs include capital charges and operating costs, estimated on an annual basis , required to upgrade petroleum residua, shale oil, or coal liquids to gas turbine fuels using conventional processes. No costs are included for production of crude oil or synthetic fuels or for transportation of these charge stocks or refined products.

Investment

1. Costs for 1984

2. Plant Location

   a. Task 3 - Petroleum - Large refineries on Gulf Coast
      Shale oil - Small refinery in Midwest

   b. Task 4 - New grass-roots refineries on Gulf Coast

3. Process Units
   Battery-limits process units for upgrading are provided as required.

   In Task 3, new supplementary units are installed when charge capacity exceeds 10% of the Base Case capacity for a given existing unit, except for the FCC and alkylation units in Case 2.33. For these units, an investment is estimated for expansion of the existing unit.

   Catalyst inventories and paid-up royalties are provided as required.

4. Field Storage Tanks

	Storage, Days
Charge stocks to upgrading units except residual hydrodesulfurization unit	7
Residual hydrodesulfurization unit	14
Gas turbine fuel product	20 (a)
Other products except propane and butanes	20 (a,b)
Propane and butanes	5 (a,b)
Refinery fuel oil	10

Table III-A (Continued)

5. Utility Units (c)
   Includes: electric substation and distribution
   package steam boilers
   cooling water tower
   boiler feed water treating by hot process lime and ion exchange
   service water treating
   fresh water pumphouse

6. Miscellaneous Off-Sites
   Includes site preparation, roads, fencing, general office buildings, communications network, field lighting, autos, trucks, compressed air plant, sewers, separators, blowdown and flare, receiving and shipping , and off-site piping.

   Estimated at 25% of investment for process units (excluding catalysts and royalties), storage tanks, and utilities in Task 3, which is based on incorporating facilities in an existing refinery, and at 33% of the investment for these facilities in Task 4 for a new grass-roots plant.

7. Contingency
   20% of investment for process units, catalysts and royalties, storage tanks, utility units, and miscellaneous off-sites.

Working Capital (Included in Task 4 only)

1. Crude Oil or Raw Material Inventory
   For one-half of storage capacity provided at delivered price.

2. Product Inventory
   For one-half of product storage capacity provided, at cost. Cost is defined as total expense less by-product credits less depreciation.

3. By-Product Inventory
   For one-half of by-product storage capacity provided, at selling price.

4. Direct Expense
   For 30 days, direct operating and maintenance expense.

5. Accounts Receivable
   For 30 days, total expense less depreciation

6. Less Accounts Payable
   For 30 days, deduction of crude oil or raw material cost.

Table III-A (Continued)

Return on Investment or Capital

Task 3: 30% before tax on total investment for upgrading plant.

Task 4: 30% before tax on total capital requirement for grass-roots upgrading plant.

Utilities and Operating Costs

1. Costs for 1985

2. Refinery fuel is supplied internally from refinery off-gas, supplemented with refinery heavy fuel oil as required. Sulfur content of refinery fuel oil is limited to a maximum of 3.0%.

3. Steam is generated internally.

4. Electric power and fresh make-up water are purchased.

5. Operating Labor Costs
   Average operating labor wage is estimated at $17.12/hr in 1985.

   Overhead Factors,

Supervision	23.5% Operating Wages
Direct Overhead for Benefits	53.1% Wages and Supervision
Allocated Overhead for Administration	22.4% Wages and Supervision
Miscellaneous Operating Expense for Laboratory and Supplies	26.0% Operating Wages

6. Investment Overhead Costs

	Gulf Coast Refinery	Mid West Refinery
Maintenance (50% labor, 50% materials)	2.0% Process Investment + 1.3% Off-Sites Investment	
Direct and Allocated Overhead Factors for Maintenance Labor are the same as for Operating Labor		
Insurance and Taxes, % Total Plant Investment	0.5	1.1
Allocated Overhead, % Total Plant Investment	1.7	2.0
Depreciation, % Total Plant Investment	4.0	4.0

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a. Minimum of two tanks.
b. In Task 3, incremental over Base Case capacity.
c. In Task 3 a new unit is provided when capacity exceeds 10% of Base Case capacity.

TABLE III-1

PRODUCTION OF GAS TURBINE FUEL FROM AN EXISTING REFINERY CHARGING LOW SULFUR CRUDE

DECARBONIZING OF VACUUM BOTTOMS

ECONOMIC EVALUATION-U.S. GULF COAST-1985

CASE		1.00 BASE CASE NO. 6 FUEL OIL PRODUCT		1.10 GAS TURBINE FUEL PRODUCT DECARBONIZING OF VACUUM BOTTOMS	
GAS TURBINE FUEL, B/CD				7801	
SULFUR, WT%				0.83	
NITROGEN, WT%				0.10	
VANADIUM, PPM				0.2	
GRAVITY, API				17.4	
VISCOSITY, CS @100F				1130	
INVESTMENT, $THOUS (1984) (1)		CAPACITY, UNITS/SD	INVEST-MENT	CAPACITY UNITS/SD	INVEST-MENT
DECARBONIZING UNIT, B CHARGE		-	-	13,840	24,170
SUBTOTAL PROCESS UNITS			-		24,170
CATALYSTS AND ROYALTIES			-		290
STORAGE TANKS			-		2,780
MISCELLANEOUS OFF-SITES			-		6,740
CONTINGENCY AT 20%			-		6,800
TOTAL PLANT INVESTMENT			-		40,780
REVENUE FROM CONVENTIONAL PRODUCTS		UNITS/CD	$THOUS/A	UNITS/CD	$THOUS/A
GASOLINE,	$ 78.35/B	111,169	3,179,183	111,169	3,179,183
JET FUEL,	$ 70.34/B	20,000	513,482	20,000	513,482
NO.2 FUEL OIL,	$ 68.65/B	57,[illegible]76	1,[illegible],214	57,591	1,443,072
BENZENE,	$131.00/B	3,[illegible]	151,574	3,170	151,574
PROPANE LPG	$ 45.59/B	[illegible]	85,531	5,140	85,531
NO.6 FUEL OIL,	$ 56.03/B	13,[illegible]	283,082	5,824	119,106
SULFUR,	$152.00/LT	29	1,609	29	1,609
REFINERY FUEL GAS,	$ 56.03/B FOE	[illegible]17	131,234	6,417	131,234
REFINERY FUEL OIL,	$ 56.03/B	6,328	129,413	6,749	138,023
TOTAL REVENUE FROM CONV. PRODUCTS			5,925,322		5,762,814
REVENUE FROM GAS TURBINE FUEL, $/B (2)			-	7,881	188,654
TOTAL REVENUE			5,925,322		5,951,468
COST OF CHARGE					
SOUTH LOUISIANA CRUDE,	$62.00/B	200,000	4,526,000	200,000	4,526,000
ISOBUTANE,	$69.58/B	11,173	283,757	11,173	283,757
NORMAL BUTANE,	$60.00/B	4,469	97,871	4,469	97,871
TOTAL COST OF CHARGE			4,907,628		4,907,628
MANUFACTURING EXPENSE					
FUEL,	$56.03/B FOE	12,745	260,647	13,166	269,257
ELECTRIC POWER,	$ 0.0654/KWH	471,900	11,265	477,090	11,388
FRESH WATER,	$ 0.0686/THOUS GAL	8,760	219	8,936	224
SUBTOTAL UTILITIES			272,131		280,869
CHEMICALS			3,720		4,270
TEL,	$9.984/THOUS CC	1281	4,668	1,281	4,668
CATALYSTS			8,023		8,023
ROYALTY, CRUDE OIL DESALT.,	$0.0056/B	200,000	409	200,000	409
LABOR BASED ITEMS (3)			-		1,092
INVESTMENT-BASED ITEMS (3)			-		3,532
TOTAL MANUFACTURING EXPENSE (3)			288,951		302,863
TOTAL EXPENSE			5,196,579		5,210,491
RETURN ON INCREMENTAL INVESTMENT AT 30% BEFORE TAXES			-		12,234
NET REVENUE, TOTAL REVENUE TOTAL EXPENSE-RETURN			728,743		728,743
CALCULATED PRICE OF GAS TURBINE FUEL, $/B (2)			-	65.58	

(1) INCREMENTAL OVER BASE CASE REFINERY, CASE 1.00.
(2) CALCULATED TO PROVIDE SAME NET REVENUE AS IN BASE CASE REFINERY, CASE 1.00.
(3) EXCLUDING LABOR AND INVESTMENT-BASED ITEMS FOR BASE CASE REFINERY, CASE 1.00.

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TABLE III-1 (CONTINUED)

PRODUCTION OF GAS TURBINE FUEL FROM AN EXISTING
REFINERY CHARGING LOW-SULFUR CRUDE

DELAYED COKING OF VACUUM BOTTOMS PLUS
HYDROGENATION OF COKER DISTILLATE

ECONOMIC EVALUATION-U.S. GULF COAST-1985

CASE	1.21	1.22	1.23
COKER DISTILLATE TO HYDROGENATION UNIT	C5-950F	375-950F	650-950F
GAS TURBINE FUEL, B/CD	9,469	6,962	3,433
SULFUR, WT%	0.05	0.07	0.09
NITROGEN, WT%	0.09	0.11	0.19
VANADIUM, PPM	0	0	0
GRAVITY, API	37.2	31.0	21.6
VISCOSITY, CS @100F	1.0	5.0	31.0

INVESTMENT, $THOUS (1984) (1)	1.21 CAPACITY, UNITS/SD	1.21 INVESTMENT	1.22 CAPACITY, UNITS/SD	1.22 INVESTMENT	1.23 CAPACITY, UNITS/SD	1.23 INVESTMENT
DELAYED COKING UNIT, B CHARGE	13,220	25,320	13,220	25,320	13,650	25,820
COKER DIST. HYDROGENATION UNIT, B CHARGE	9,860	10,210	7,250	8,130	3,600	5,250
HYDROGEN SULFIDE RECOVERY UNIT, LT H2S	13	3,900	13	3,900	13	3,900
SULFUR PLANT, LT SULFUR	13	5,550	12	5,370	12	5,370
SUBTOTAL PROCESS UNITS		44,980		42,720		40,340
CATALYSTS AND ROYALTIES		1,120		830		540
UTILITY UNITS		720		730		720
STORAGE TANKS		3,970		3,990		3,260
MISCELLANEOUS OFF-SITES		12,420		11,860		11,080
CONTINGENCY AT 20%		12,640		12,030		11,190
TOTAL PLANT INVESTMENT		75,850		72,160		67,130

		1.21 UNITS/CD	1.21 $THOUS/A	1.22 UNITS/CD	1.22 $THOUS/A	1.23 UNITS/CD	1.23 $THOUS/A
REVENUE FROM CONVENTIONAL PRODUCTS							
GASOLINE,	$ 78.35/B	111,705	3,194,512	113,582	3,248,190	117,062	3,347,710
JET FUEL,	$ 70.34/B	20,000	513,482	20,000	513,482	20,000	513,482
NO.2 FUEL OIL,	$ 68.65/B	59,115	1,481,259	59,204	1,483,489	59,644	1,494,515
BENZENE,	$131.00/B	3,170	151,574	3,395	162,332	3,387	161,949
PROPANE LPG	$ 45.59/B	5,489	91,339	5,635	93,768	5,797	96,464
COKE,	$173.00/ST	658	41,549	658	41,549	680	42,939
SULFUR,	$152.00/LT	41	2,275	41	2,275	40	2,219
REFINERY FUEL GAS,	$ 56.03/B FOE	6,811	139,291	7,041	143,995	7,293	149,149
REFINERY FUEL OIL,	$ 56.03/B	6,500	132,931	6,517	133,279	6,352	129,904
TOTAL REVENUE FROM CONV. PRODUCTS			5,748,212		5,822,359		5,938,331
REVENUE FROM GAS TURBINE FUEL, $/B (2)		9,469	227,947	6,962	158,083	3,433	58,177
TOTAL REVENUE			5,976,159		5,980,442		5,996,508
COST OF CHARGE							
SOUTH LOUISIANA CRUDE,	$62.00/B	200,000	4,526,000	200,000	4,526,000	200,000	4,526,000
ISOBUTANE,	$69.58/B	11,482	291,647	11,413	289,853	11,943	303,313
NORMAL BUTANE,	$60.00/B	4,326	94,739	4,433	97,082	4,538	99,382
TOTAL COST OF CHARGE			4,912,386		4,912,935		4,928,695
MANUFACTURING EXPENSE							
FUEL,	$56.03/B	13,311	272,222	13,558	277,274	13,645	279,053
ELECTRIC POWER,	$ 0.0654/KWH	540,150	12,894	543,440	12,972	541,120	12,917
FRESH WATER,	$ 0.0686/THOUS GAL.	9,094	228	9,227	231	9,394	235
SUBTOTAL UTILITIES			285,344		290,477		292,205
CHEMICALS			3,820		3,858		3,925
TEL,	$9.984/THOUS CC	1,277	4,654	1,276	4,650	1,312	4,781
CATALYSTS			8,214		8,204		8,516
ROYALTY, CRUDE OIL DESALT.,	$0.0056/B	200,000	409	200,000	409	200,000	409
LABOR-BASED ITEMS (3)			3,276		3,276		3,276
INVESTMENT-BASED ITEMS (3)			6,558		6,242		5,819
TOTAL MANUFACTURING EXPENSE (3)			312,275		317,116		318,931
TOTAL EXPENSE			5,224,661		5,230,051		5,247,626
RETURN ON INCREMENTAL INVESTMENT AT 30% BEFORE TAXES			22,755		21,648		20,139
NET REVENUE, TOTAL REVENUE-TOTAL EXPENSE-RETURN			728,743		728,743		728,743
CALCULATED PRICE OF GAS TURBINE FUEL, $/B (2)		65.95		62.21		46.43	

(1) INCREMENTAL OVER BASE CASE REFINERY, CASE 1.00.
(2) CALCULATED TO PROVIDE SAME NET REVENUE AS IN BASE CASE REFINERY, CASE 1.00.
(3) EXCLUDING LABOR AND INVESTMENT-BASED ITEMS FOR BASE CASE REFINERY, CASE 1.00.

TABLE III-1 (CONTINUED)

PRODUCTION OF GAS TURBINE FUEL FROM AN EXISTING
REFINERY CHARGING LOW-SULFUR CRUDE

HYDRODESULFURIZATION OF VACUUM BOTTOMS

ECONOMIC EVALUATION-U.S. GULF COAST-1985

CASE HYDRDESULFURIZAION SEVERITY		1.31 MODERATE		1.32 INTERMEDIATE		1.33 HIGH	
GAS TURBINE FUEL, B/CD		17,103		16,830		16,714	
SULFUR, WT%		0.25		0.21		0.17	
NITROGEN, WT%		0.09		0.09		0.09	
VANADIUM, PPM		1.3		0.6		0.1	
GRAVITY, API		22.9		23.1		23.4	
VISCOSITY, CS @100F		1100		1100		1100	
INVESTMENT, $THOUS (1984) (1)		CAPACITY, UNITS/SD	INVEST-MENT	CAPACITY, UNITS/SD	INVEST-MENT	CAPACITY, UNITS/SD	INVEST-MENT
HYDRODESULFURIZATION UNIT, B CHARGE		13,220	23,890	13,190	25,230	13,160	25,900
HYDROGEN SULFIDE RECOVERY UNIT, LT H2S		17	4,250	17	4,250	19	4,410
SULFUR PLANT, LT SULFUR		16	6,040	16	6,040	17	6,190
SUBTOTAL PROCESS UNITS			34,180		35,520		36,500
CATALYSTS AND ROYALTIES			3,250		3,490		3,630
UTILITY UNITS			640		650		660
STORAGE TANKS			2,730		2,680		2,650
MISCELLANEOUS OFF-SITES			9,390		9,710		9,950
CONTINGENCY AT 20%			10,040		10,410		10,680
TOTAL PLANT INVESTMENT			60,230		62,460		64,070
REVENUE FROM CONVENTIONAL PRODUCTS		UNITS/CD	$THOUS/A	UNITS/CD	$THOUS/A	UNITS/CD	$THOUS/A
GASOLINE,	$ 78.35/B	111,242	3,181,271	111,253	3,181,585	111,260	3,181,786
JET FUEL,	$ 70.34/B	20,000	513,482	20,000	513,482	20,000	513,482
NO.2 FUEL OIL,	$ 68.65/B	54,993	1,377,973	55,273	1,384,989	55,383	1,387,746
BENZENE,	$131.00/B	3,180	152,052	3,181	152,100	3,181	152,100
PROPANE LPG	$ 45.59/B	5,158	85,831	5,160	85,864	5,162	85,897
SULFUR,	$152.00/LT	44	2,441	44	2,441	46	2,552
AMMONIA,	$312.00/ST	2.1	239	2.5	285	3.0	342
REFINERY FUEL GAS,	$ 56.03/B FOE	6,206	126,918	6,189	126,571	6,170	126,182
REFINERY FUEL OIL,	$ 56.03/B	6,774	138,535	6,795	138,964	6,823	139,537
TOTAL REVENUE FROM CONV. PRODUCTS			5,578,742		5,586,281		5,589,624
REVENUE FROM GAS TURBINE FUEL, $/B (2)		17,103	379,019	16,830	372,712	16,714	370,353
TOTAL REVENUE			5,957,761		5,958,993		5,959,977
COST OF CHARGE							
SOUTH LOUISIANA CRUDE,	$62.00/B	200,000	4,526,000	200,000	4,526,000	200,000	4,526,000
ISOBUTANE,	$69.58/B	11,168	283,630	11,168	283,630	11,167	283,605
NORMAL BUTANE,	$60.00/B	4,476	98,024	4,476	98,024	4,476	98,024
TOTAL COST OF CHARGE			4,907,654		4,907,654		4,907,629
MANUFACTURING EXPENSE							
FUEL,	$56.03/B	12,980	265,453	12,984	265,535	12,993	265,719
ELECTRIC POWER,	$ 0.0654/KWH	525,320	12,540	527,010	12,580	529,140	12,631
FRESH WATER,	$ 0.0686/THOUS GAL	8,938	224	8,947	224	8,959	224
SUBTOTAL UTILITIES			278,217		278,339		278,574
CHEMICALS			3,748		3,755		3,765
TEL,	$9.984/THOUS CC	1,281	4,668	1,281	4,668	1,282	4,672
CATALYSTS			8,931		9,176		9,316
ROYALTY, CRUDE OIL DESALT.,	$0.0056/B	200,000	409	200,000	409	200,000	409
LABOR-BASED ITEMS (3)			2,184		2,184		2,184
INVESTMENT-BASED ITEMS (3)			5,138		5,327		5,464
TOTAL MANUFACTURING EXPENSE (3)			303,295		303,858		304,384
TOTAL EXPENSE			5,210,949		5,211,512		5,212,013
RETURN ON INCREMENTAL INVESTMENT AT 30% BEFORE TAXES			18,069		18,738		19,221
NET REVENUE, TOTAL REVENUE-TOTAL EXPENSE-RETURN			728,743		728,743		728,743
CALCULATED PRICE OF GAS TURBINE FUEL, $/B (2)		60.72		60.67		60.71	

(1) INCREMENTAL OVER BASE CASE REFINERY, CASE 1.00.
(2) CALCULATED TO PROVIDE SAME NET REVENUE AS IN BASE CASE REFINERY, CASE 1.00.
(3) EXCLUDING LABOR AND INVESTMENT-BASED ITEMS FOR BASE CASE REFINERY, CASE 1.00.

TABLE III-2

PRODUCTION OF GAS TURBINE FUEL FROM AN EXISTING
REFINERY CHARGING HIGH-SULFUR CRUDE

DECARBONIZING OF VACUUM BOTTOMS PLUS
HYDRODESULFURIZATION OF DECARBONIZED OIL

ECONOMIC EVALUATION-U.S. GULF COAST-1985

CASE		2.00 BASE CASE NO. 6 FUEL OIL PRODUCT		2.10 GAS TURBINE FUEL PRODUCT DECARBONIZING OF VACUUM BOTTOMS	
GAS TURBINE FUEL, B/CD			-	19,392	
SULFUR, WT%				0.26	
NITROGEN, WT%				0.27	
VANADIUM, PPM				11.6	
GRAVITY, API				21.7	
VISCOSITY, CS @100F				1,130	
INVESTMENT, $THOUS (1984) (1)		CAPACITY, UNITS/SD	INVEST-MENT	CAPACITY, UNITS/SD	INVEST-MENT
DECARBONIZING UNIT, B CHARGE		-	-	22,840	32,800
DECARB. OIL DESULFURIZATION UNIT, B CHARGE		-	-	17,120	18,180
FURNACE OIL GULFINING UNIT, B CHARGE		-	-	2,770	3,110
HYDROGEN SULFIDE RECOVERY UNIT, LT H2S		-	-	77	6,920
SULFUR PLANT, LT SULFUR			-	73	11,180
SUBTOTAL PROCESS UNITS			-		72,190
CATALYSTS AND ROYALTIES			-		4,220
UTILITY UNITS			-		5,060
STORAGE TANKS			-		3,630
MISCELLANEOUS OFF-SITES			-		20,220
CONTINGENCY AT 20%			-		21,060
TOTAL PLANT INVESTMENT					126,380
REVENUE FROM CONVENTIONAL PRODUCTS		UNITS/CD	$THOUS/A	UNITS/CD	$THOUS/A
GASOLINE,	$ 78.35/B	48,823	1,396,228	48,823	1,396,228
NO.2 FUEL OIL,	$ 68.65/B	22,087	553,439	22,857	572,733
PROPANE LPG	$ 45.59/B	2,803	46,643	2,803	46,643
NO.6 FUEL OIL,	$ 53.00/B	29,217	565,203	7,620	147,409
SULFUR,	$152.00/LT	36	1,997	104	5,770
REFINERY FUEL GAS,	$ 56.03/B FOE	3,137	64,165	2,729	55,811
REFINERY FUEL OIL,	$ 53.00/B	2,191	42,385	3,837	74,227
TOTAL REVENUE FROM CONV. PRODUCTS			2,670,060		2,298,821
REVENUE FROM GAS TURBINE FUEL, $/B (2)		-	-	19,392	450,698
TOTAL REVENUE			2,670,060		2,749,519
COST OF CHARGE					
CEUTA (VENEZUELAN) CRUDE,	$59.00/B	100,000	2,153,500	100,000	2,153,500
ISOBUTANE,	$69.58/B	4,230	107,428	4,230	107,428
NORMAL BUTANE,	$60.00/B	1,440	31,536	1,440	31,536
TOTAL COST OF CHARGE			2,292,464		2,292,464
MANUFACTURING EXPENSE					
FUEL		5,328	106,550	6,566	130,038
ELECTRIC POWER,	$ 0.0654/KWH	209,590	5,003	276,550	6,602
FRESH WATER,	$ 0.0686/THOUS GAL	3,546	89	4,196	105
SUBTOTAL UTILITIES			111,642		136,745
CHEMICALS			1,412		2,637
TEL,	$9.984/THOUS CC	557	2,030	557	2,030
CATALYSTS			1,835		2,568
ROYALTY, CRUDE OIL DESALT.,	$0.0056/B	100,000	204	100,000	204
LABOR-BASED ITEMS (3)			-		3,640
INVESTMENT-BASED ITEMS (3)			-		10,844
TOTAL MANUFACTURING EXPENSE (3)			117,123		158,668
TOTAL EXPENSE			2,409,587		2,451,132
RETURN ON INCREMENTAL INVESTMENT AT 30% BEFORE TAXES			-		37,914
NET REVENUE, TOTAL REVENUE-TOTAL EXPENSE-RETURN			260,473		260,473
CALCULATED PRICE OF GAS TURBINE FUEL, $/B (2)			-	63.68	

(1) INCREMENTAL OVER BASE CASE REFINERY, CASE 2.00.
(2) CALCULATED TO PROVIDE SAME NET REVENUE AS IN BASE CASE REFINERY, CASE 2.00.
(3) EXCLUDING LABOR AND INVESTMENT-BASED ITEMS FOR BASE CASE REFINERY, CASE 2.00.

TABLE III-2 (CONTINUED)

PRODUCTION OF GAS TURBINE FUEL FROM AN EXISTING
REFINERY CHARGING HIGH SULFUR CRUDE

DELAYED COKING OF VACUUM BOTTOMS PLUS
HYDROGENATION OF COKER DISTILLATE

ECONOMIC EVALUATION U.S. GULF COAST 1985

CASE	2.21	2.22	2.23
COKER DISTILLATE TO HYDROGENATION UNIT	C5-950F	375-950F	650-950F
GAS TURBINE FUEL, B/CD	15,263	11,261	5,418
SULFUR, WT%	0.16	0.20	0.25
NITROGEN, WT%	0.09	0.11	0.19
VANADIUM, PPM	0	0	0
GRAVITY, API	37.7	31.5	22.3
VISCOSITY, CS @100F	1.0	5.0	26.5

INVESTMENT, $THOUS (1984) (1)	CAPACITY, UNITS/SD	INVEST-MENT	CAPACITY, UNITS/SD	INVEST-MENT	CAPACITY, UNITS/SD	INVEST-MENT
DELAYED COKING UNIT, B CHARGE	22,610	35,130	22,700	35,210	22,840	35,340
COKER DIST. HYDROGENATION UNIT, B CHARGE	16,020	14,630	11,840	11,690	5,750	7,430
NAPHTHA PRETREATING/REFORMING UNIT, B CHGE	-	-	3,680	12,330	3,700	12,330
FURNACE OIL GULFINING UNIT, B CHARGE	3,740	3,890	3.740	3,890	4,430	4,410
FCC UNIT, B CHARGE (REVAMP)	-	-	-	-	6,160	5,000
ALKYLATION UNIT, B CHARGE (REVAMP)	-	-	-	-	2,760	1,000
GASOLINE SWEETENING UNITS, B CHARGE	-	-	670	120	3,860	550
GAS PLANT	-	-	-	1,160	-	1,100
HYDROGEN SULFIDE RECOVERY UNIT, LT H2S	76	6,890	77	6,920	75	6,860
SULFUR PLANT, LT SULFUR	72	11,110	72	11,110	71	11,050
SUBTOTAL PROCESS UNITS		71,650		82,430		85,070
CATALYSTS AND ROYALTIES		2,150		3,070		3,400
UTILITY UNITS		4,300		4,480		5,790
STORAGE TANKS		4,120		5,510		7,690
MISCELLANEOUS OFF-SITES		20,020		23,110		24,640
CONTINGENCY AT 20%		20,450		23,720		25,320
TOTAL PLANT INVESTMENT		122,690		142,320		151,910

REVENUE FROM CONVENTIONAL PRODUCTS		UNITS/CD	$THOUS/A	UNITS/CD	$THOUS/A	UNITS/CD	$THOUS/A
GASOLINE,	$ 78.35/B	49,715	1,421,737	53,505	1,530,123	58,700	1,678,688
NO.2 FUEL OIL,	$ 68.65/B	29,399	736,658	29,399	736,658	30,146	755,376
PROPANE LPG	$ 45.59/B	3,305	56,328	3,605	59,988	3,843	63,949
NO.6 FUEL OIL,	$ 53.00/B	-	-	-	-	661	12,787
COKE,	$ 40.00/ST	1,232	17,987	1,237	18,060	1,245	18,177
SULFUR,	$152.00/LT	104	5,770	104	5,770	102	5,659
REFINERY FUEL GAS,	$ 56.03/B FOE	3,611	73,848	3,914	80,045	4,322	88,389
REFINERY FUEL OIL,	$ 53.00/B	2,841	54,959	2,762	53,431	2,468	47,743
TOTAL REVENUE FROM CONV. PRODUCTS			2,367,287		2,484,075		2,670,768
REVENUE FROM GAS TURBINE FUEL, $/B (2)		15,263	388,805	11,261	289,571	5,418	138,139
TOTAL REVENUE			2,756,092		2,773,646		2,808,907
COST OF CHARGE							
CEUTA (VENEZUELAN) CRUDE,	$59.00/B	100,000	2,153,500	100,000	2,153,500	100,000	2,153,500
ISOBUTANE,	$69.58/B	4,742	120,431	4,633	117,663	5,605	142,349
NORMAL BUTANE,	$60.00/B	1,201	26,302	1,479	32,390	1,650	36,135
TOTAL COST OF CHARGE			2,300,233		2,303,553		2,331,984
MANUFACTURING EXPENSE							
FUEL		6,452	128,807	6,676	133,476	6,790	136,132
ELECTRIC POWER,	$ 0.0654/KWH	338,730	8,086	338,785	8,087	334,800	7,992
FRESH WATER,	$ 0.0686/THOUS GAL	4,310	108	4,425	111	4,690	117
SUBTOTAL UTILITIES			137,001		141,674		144,241
CHEMICALS			1,809		1,839		1,964
TEL,	$9.984/THOUS CC	556	2,027	601	2,189	661	2,409
CATALYSTS			2,219		2,205		2,456
ROYALTY, CRUDE OIL DESALT.,	$0.0056/B	100,000	204	100,000	204	100,000	204
LABOR-BASED ITEMS (3)			4,732		6,553		6,553
INVESTMENT-BASED ITEMS (3)			10,587		12,260		13,050
TOTAL MANUFACTURING EXPENSE (3)			158,579		166,924		170,877
TOTAL EXPENSE			2,458,812		2,470,477		2,502,861
RETURN ON INCREMENTAL INVESTMENT AT 30% BEFORE TAXES			36,807		42,696		45,573
NET REVENUE, TOTAL REVENUE-TOTAL EXPENSE-RETURN			260,473		260,473		260,473
CALCULATED PRICE OF GAS TURBINE FUEL, $/B (2)			69.79		70.45		69.85

(1) INCREMENTAL OVER BASE CASE REFINERY, CASE 2.00.
(2) CALCULATED TO PROVIDE SAME NET REVENUE AS IN BASE CASE REFINERY, CASE 2.00.
(3) EXCLUDING LABOR AND INVESTMENT-BASED ITEMS FOR BASE CASE REFINERY, CASE 2.00.

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TABLE III-2 (CONTINUED)

PRODUCTION OF GAS TURBINE FUEL FROM AN EXISTING REFINERY CHARGING HIGH-SULFUR CRUDE

HYDRODESULFURIZATION OF VACUUM BOTTOMS

ECONOMIC EVALUATION-U.S. GULF COAST-1985

CASE	2.31	2.32	2.33
HYDRODESULFURIZATION SEVERITY	MODERATE	INTERMEDIATE	HIGH
GAS TURBINE FUEL, B/CD	25,325	25,096	24,730
SULFUR, WT%	0.37	0.29	0.20
NITROGEN, WT%	0.36	0.36	0.30
VANADIUM, PPM	50.4	31.0	10.9
GRAVITY, API	23.0	23.2	23.4
VISCOSITY, CS @100F	1,130	1,130	1,130

INVESTMENT, $THOUS (1984) (1)	CAPACITY, UNITS/SD	INVEST-MENT	CAPACITY, UNITS/SD	INVEST-MENT	CAPACITY, UNITS/SD	INVEST-MENT
HYDRODESULFURIZATION UNIT, B CHARGE	22,200	106,660	22,130	110,880	22,050	117,540
HYDROGEN MFG PLANT, THOUS SCF	4,420	7,560	5,440	8,740	6,790	10,210
FURNACE OIL GULFINING UNIT, B CHARGE	3,620	3,800	3,620	3,800	3,630	3,800
HYDROGEN SULFIDE RECOVERY UNIT, LT H2S	113	7,830	115	7,870	119	7,960
SULFUR PLANT, LT SULFUR	106	13,000	109	13,150	112	13,300
SUBTOTAL PROCESS UNITS		138,850		144,440		152,810
CATALYSTS AND ROYALTIES		17,970		18,890		21,260
UTILITY UNITS		5,850		5,960		6,010
STORAGE TANKS		4,500		4,520		4,580
MISCELLANEOUS OFF-SITES		37,300		38,730		40,850
CONTINGENCY AT 20%		40,890		42,510		45,100
TOTAL PLANT INVESTMENT		245,360		255,050		270,610

REVENUE FROM CONVENTIONAL PRODUCTS		UNITS/CD	$THOUS/A	UNITS/CD	$THOUS/A	UNITS/CD	$THOUS/A
GASOLINE,	$ 78.35/B	49,342	1,411,070	49,361	1,411,614	49,383	1,412,243
NO.2 FUEL OIL,	$ 68.65/B	25,273	633,272	25,444	637,557	25,743	645,049
PROPANE LPG	$ 45.59/B	2,892	48,124	2,896	48,190	2,899	48,240
SULFUR,	$152.00/LT	136	7,545	138	7,656	141	7,823
AMMONIA,	$312.00/ST	6.9	786	6.9	786	9.0	1,025
REFINERY FUEL GAS,	$ 56.03/B FOE	2,536	51,864	2,552	52,191	2,571	52,579
REFINERY FUEL OIL,	$ 53.00/B	3,676	71,112	3,736	72,273	3,807	73,646
TOTAL REVENUE FROM CONV. PRODUCTS			2,223,773		2,230,267		2,240,605
REVENUE FROM GAS TURBINE FUEL, $/B (2)		25,325	580,086	25,096	579,883	24,730	579,179
TOTAL REVENUE			2,803,859		2,810,150		2,819,784
COST OF CHARGE							
CEUTA (VENEZUELAN) CRUDE,	$59.00/B	100,000	2,153,500	100,000	2,153,500	100,000	2,153,500
ISOBUTANE,	$69.58/B	4,202	106,717	4,201	106,692	4,199	106,641
NORMAL BUTANE,	$60.00/B	1,461	31,996	1,461	31,996	1,461	31,996
TOTAL COST OF CHARGE			2,292,213		2,292,188		2,292,137
MANUFACTURING EXPENSE							
FUEL		6,212	122,976	6,288	124,464	6,378	126,225
ELECTRIC POWER,	$ 0.0654/KWH	368,630	8,800	375,910	8,973	382,830	9,139
FRESH WATER,	$ 0.0686/THOUS GAL	4,319	108	4,353	109	4,399	110
SUBTOTAL UTILITIES			131,884		133,546		135,474
CHEMICALS			1,969		1,988		2,012
TEL,	$9.984/THOUS CC	568	2,069	569	2,074	569	2,074
CATALYSTS			15,876		16,784		18,560
ROYALTY, CRUDE DESALTING,	$0.0056/B	100,000	204	100,000	204	100,000	204
LABOR-BASED ITEMS (3)			4,732		4,732		4,732
INVESTMENT-BASED ITEMS (3)			20,831		21,646		22,935
TOTAL MANUFACTURING EXPENSE (3)			177,565		180,974		185,991
TOTAL EXPENSE			2,469,778		2,473,162		2,478,128
RETURN ON INCREMENTAL INVESTMENT AT 30% BEFORE TAXES			73,608		76,515		81,183
NET REVENUE, TOTAL REVENUE-TOTAL EXPENSE-RETURN			260,473		260,473		260,473
CALCULATED PRICE OF GAS TURBINE FUEL, $/B (2)			62.76		63.31		64.16

(1) INCREMENTAL OVER BASE CASE REFINERY, CASE 2.00.
(2) CALCULATED TO PROVIDE SAME NET REVENUE AS IN BASE CASE REFINERY, CASE 2.00.
(3) EXCLUDING LABOR AND INVESTMENT-BASED ITEMS FOR BASE CASE REFINERY, CASE 2.00.

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TABLE III-3

PRODUCTION OF GAS TURBINE FUEL FROM SURFACE RETORTED SHALE OIL IN AN EXISTING REFINERY

ECONOMIC EVALUATION-U.S. GULF COAST 1985

CASE	3.00 BASE CASE NO.2 FUEL OIL PRODUCT SOUTH LOUISIANA CRUDE	3.01 BASE CASE NO.2 FUEL OIL PRODUCT PARAHO SHALE OIL	3.10 GAS TURBINE FUEL PRODUCT SEVERE HYDROTREATING PLUS GULFINING OF DISTILLATE
GAS TURBINE FUEL, B/CD	-	-	21,869
SULFUR, WT%			0.0015
NITROGEN, WT%			0.019
VANADIUM, PPM			0.2
GRAVITY, API			38.5
VISCOSITY, CS AT 100F			2.35

INVESTMENT, $ THOUS (1984) (1)	3.00 CAPACITY, UNITS/SD	3.00 INVESTMENT	3.01 CAPACITY, UNITS/SD	3.01 INVESTMENT	3.10 CAPACITY, UNITS/SD	3.10 INVESTMENT
SHALE OIL DEMINERALIZING UNIT, B CHARGE	-	-	58,820	2,070	58,820	2,070
HYDROTREATING UNIT, B CHARGE	-		58,820	106,650	58,820	106,650
NAPHTHA PRETREATING UNIT, B CHARGE	-	-	8,940	6,810	8,940	6,810
DISTILLATE GULFINING UNIT, B CHARGE	-	-	23,220	17,840	23,220	17,840
HYDROGEN MFG PLANT, THOUS SCF	-	-	2-61,850	96,540	2-61,850	96,540
HYDROGEN SULFIDE RECOVERY UNIT, LT	-	-	59	6,360	59	6,360
SULFUR PLANT, LT	-	-	56	10,030	56	10,030
WASTE WATER TREATING UNIT	-	-		22,970		22,970
SUBTOTAL PROCESS UNITS		-		269,270		269,270
CATALYSTS AND ROYALTIES		-		29,840		29,840
UTILITY UNITS		-		8,200		8,200
MISCELLANEOUS OFF-SITES		-		69,370		69,370
CONTINGENCY AT 20%		-		75,340		75,340
TOTAL PLANT INVESTMENT		-		452,020		452,020

		3.00 UNITS/CD	3.00 $THOUS/A	3.01 UNITS/CD	3.01 $THOUS/A	3.10 UNITS/CD	3.10 $THOUS/A
REVENUE FROM CONVENTIONAL PRODUCTS							
GASOLINE,	$ 78.35/B	29,034	830,307	28,543	816,266	28,543	816,266
JET FUEL,	$ 70.34/B	2,100	53,916	-	-	-	-
NO.2 FUEL OIL,	$ 68.65/B	15,634	391,745	21,869	547,977	-	-
PROPANE LPG,	$ 45.59/B	989	16,457	872	14,510	872	14,510
NO.6 FUEL OIL,	$ 56.03/B	5,224	106,836	-	-	-	-
SULFUR,	$152.00/LT	7	388	47	2,608	47	2,608
AMMONIA,	$312.00/ST			208	23,687	208	23,687
GAS TO H2 PLANT FEED,	$ 56.03/B FOE		-	4,292	87,775	4,292	87,775
REFINERY FUEL GAS,	$ 56.03/B FOE	2,092	42,784	-	-	-	-
REFINERY FUEL OIL,	$ 56.03/B	380	7,771	5,049	103,257	5,049	103,257
TOTAL REVENUE FROM CONV. PRODUCTS			1,450,204		1,596,080		1,048,103
REVENUE FROM GAS TURBINE FUEL, $68.63/B (2)					-	21,869	547,803
TOTAL REVENUE			1,450,204		1,596,080		1,595,906
COST OF CHARGE							
SOUTH LOUISIANA CRUDE,	$ 62.00/B	50,000	1,131,500	-	-	-	-
PARAHO SHALE OIL,	$ 50.86/B (2)	-	-	50,000	928,121	50,000	928,121
ISOBUTANE,	$ 69.58/B	2,030	51,555	1,677	42,590	1,677	42,590
NORMAL BUTANE,	$ 60.00/B	1,305	28,580	1,713	37,515	1,713	37,515
TOTAL COST OF CHARGE			1,211,635		1,008,226		1,008,226
MANUFACTURING EXPENSE							
FUEL,	$ 56.03/B FOE	2,472	50,555	5,049	103,257	5,049	103,257
ELECTRIC POWER,	$ 0.0654/KWH	116,170	2,773	364,550	8,702	364,550	8,702
FRESH WATER,	$0.0686/THOUS GAL	2,379	60	6,155	154	6,155	154
SUBTOTAL UTILITIES			53,388		112,113		112,113
GAS TO H2 PLANT FEED,	$ 56.03/B FOE	-	-	4,292	87,775	4,292	87,775
CHEMICALS			898		1,499		1,325
TEL,	$ 9.984/THOUS CC	318	1,159	245	892	245	892
CATALYSTS			2,001		24,324		24,324
ROYALTY, DEMINERALIZING,	$ 0.0056/B	50,000	102	50,000	102	50,000	102
LABOR-BASED ITEMS (3)			-		2,182		2,182
INVESTMENT-BASED ITEMS (3)			-		42,340		42,340
TOTAL MANUFACTURING EXPENSE (3)			57,548		271,227		271,053
TOTAL EXPENSE			1,269,183		1,279,453		1,279,279
RETURN ON INCREMENTAL INVESTMENT AT 30% BEFORE TAXES			-		135,606		135,606
NET REVENUE, TOTAL REVENUE-TOTAL EXPENSE-RETURN			181,021		181,021		181,021
CALCULATED PRICE OF GAS TURBINE FUEL, $/B (2)			-		-		68.63

1 INCREMENTAL OVER BASE CASE REFINERY, CASE 3.00.
2 CALCULATED TO PROVIDE SAME NET REVENUE AS IN BASE CASE REFINERY, CASE 3.00.
3 EXCLUDING LABOR AND INVESTMENT-BASED ITEMS IN BASE CASE REFINERY, CASE 3.00.

TABLE III-3 (CONTINUED)

PRODUCTION OF GAS TURBINE FUEL FROM SURFACE-RETORTED SHALE OIL IN AN EXISTING REFINERY

ECONOMIC EVALUATION-U.S. GULF COAST-1985

CASE	3.20 GAS TURBINE FUEL PRODUCT SEVERE HYDROTREATING NO GULFINING OF DISTILLATE	3.30 GAS TURBINE FUEL PRODUCT COKING PLUS HYDROTREATING NO GULFINING OF DISTILLATE
GAS TURBINE FUEL, B/CD	22,156	32,273
SULFUR, WT%	0.004	0.008
NITROGEN, WT%	0.05	0.3
VANADIUM, PPM	0.2	0.0
GRAVITY, API	37.5	39.0
VISCOSITY, CS @100F	2.35	2.4

INVESTMENT, $THOUS (1984) (1)	CAPACITY, UNITS/SD	INVEST-MENT	CAPACITY, UNITS/SD	INVEST-MENT
SHALE OIL DEMINERALIZING UNIT, B CHARGE	58,820	2,070	55,560	2,000
HYDROTREATING UNIT, B CHARGE	58,820	106,650	44,910	52,080
DELAYED COKING UNIT, B CHARGE	-	-	55,560	60,790
NAPHTHA PRETREATING UNIT, B CHARGE	8,940	6,810	7,020	5,850
HYDROGEN MFG PLANT, THOUS SCF	2 AT 60,060	94,570	53,560	43,630
HYDROGEN SULFIDE RECOVERY UNIT, LT	59	6,350	48	5,930
SULFUR PLANT, LT	56	10,010	45	9,100
WASTE WATER TREATING UNIT		22,970		16,940
SUBTOTAL PROCESS UNITS		249,430		196,400
CATALYSTS AND ROYALTIES		28,670		12,630
UTILITY UNITS		7,350		2,810
STORAGE TANKS				410
MISCELLANEOUS OFF-SITES		64,200		49,910
CONTINGENCY AT 20%		69,930		52,430
TOTAL PLANT INVESTMENT		419,500		314,590

REVENUE FROM CONVENTIONAL PRODUCTS		UNITS/CD	$THOUS/A	UNITS/CD	$THOUS/A
GASOLINE,	$ 78.35/B	28,543	816,266	6,714	192,005
PROPANE LPG	$ 45.59/B	872	14,510	325	5,408
BUTANES,	$ 60.00/B	-	-	250	5,475
SULFUR,	$152.00/LT	47	2,608	40	2,219
AMMONIA,	$312.00/ST	208	23,687	130	14,804
COKE,	$ 40.00/ST	-	-	1,551	22,645
GAS TO H2 PLANT FEED,	$ 56.03/B FOE	4,167	85,219	1,914	39,143
REFINERY FUEL GAS,	$ 56.03/B FOE	38	777	1,731	35,401
REFINERY FUEL OIL,	$ 56.03/B	4,716	96,447	1,961	40,104
TOTAL REVENUE FROM CONV. PRODUCTS			1,039,514		357,204
REVENUE FROM GAS TURBINE FUEL, $/B (2)		22,156	533,144	32,273	1,008,045
TOTAL REVENUE			1,572,658		1,365,249
COST OF CHARGE					
PARAHO SHALE OIL,	$ 50.86/B (2)	50,000	928,121	50,000	928,121
ISOBUTANE,	$ 69.58/B	1,677	42,590	-	-
NORMAL BUTANE,	$ 60.00/B	1,713	37,515	-	-
TOTAL COST OF CHARGE			1,008,226		928,121
MANUFACTURING EXPENSE					
FUEL,	$56.03/B FOE	4,754	97,224	3,692	75,505
ELECTRIC POWER,	$ 0.0654/KWH	319,720	7,632	286,360	6,836
FRESH WATER,	$ 0.0686/THOUS GAL	5,917	148	3,846	96
SUBTOTAL UTILITIES			105,004		82,437
GAS TO H2 PLANT FEED,	$56.03/B FOE	4,167	85,219	1,914	39,143
CHEMICALS			1,478		641
TEL,	$9.984/THOUS CC	245	892	77	281
CATALYSTS			24,124		7,110
ROYALTY, DEMINERALIZING,	$0.0056/B	50,000	102	50,000	102
LABOR-BASED ITEMS, (3)			1,454		2,182
INVESTMENT-BASED ITEMS (3)			39,264		29,834
TOTAL MANUFACTURING EXPENSE (3)			257,537		161,730
TOTAL EXPENSE			1,265,763		1,089,851
RETURN ON INCREMENTAL INVESTMENT AT 30% BEFORE TAXES			125,874		94,377
NET REVENUE, TOTAL REVENUE-TOTAL EXPENSE-RETURN			181,021		181,021
CALCULATED PRICE OF GAS TURBINE FUEL, $/B			65.93		85.58

1 INCREMENTAL OVER BASE CASE REFINERY, CASE 3.00.
2 CALCULATED TO PROVIDE SAME NET REVENUE AS IN BASE CASE REFINERY, CASE 3.00.
3 EXCLUDING LABOR AND INVESTMENT-BASED ITEMS IN BASE CASE REFINERY, CASE 3.00.

TABLE III 4

PRODUCTION OF GAS TURBINE FUEL FROM MODIFIED IN SITU RETORTED SHALE OIL IN AN EXISTING REFINERY

ECONOMIC EVALUATION-U.S. GULF COAST 1985

CASE		4.01 BASE CASE NO.2 FUEL OIL PRODUCT MIS SHALE OIL		4.10 GAS TURBINE FUEL PRODUCT SEVERE HYDROTREATING, GULFINING OF DISTILLATE		4.20 GAS TURBINE FUEL PRODUCT SEVERE HYDROTREATING, NO GULFINING OF DISTILLATE	
GAS TURBINE FUEL B/CD				26,127		26,461	
SULFUR, WT%				0.0015		0.004	
NITROGEN, WT%				0.019		0.05	
VANADIUM PPM				0.2		0.2	
GRAVITY, API				37.2		36.7	
VISCOSITY CS AT 100F				2.35		2.35	
INVESTMENT, $ THOUS (1984) (1)		CAPACITY, UNITS/SD	INVEST MENT	CAPACITY, UNITS/SD	INVEST MENT	CAPACITY, UNITS/SD	INVEST MENT
SHALE OIL DEMINERALIZING UNIT, B CHARGE		58,820	2,070	58,820	2,070	58,820	2,070
HYDROTREATING UNIT, B CHARGE		58,820	99,940	58,820	99,940	58,820	99,940
NAPHTHA PRETREATING UNIT, B CHARGE		6,170	5,390	6,170	5,390	6,170	5,390
DISTILLATE GULFINING UNIT, B CHARGE		27,730	20,350	27,730	20,350		
HYDROGEN MFG PLANT, THOUS SCF		74,630	55,080	74,630	55,080	70,370	52,850
HYDROGEN SULFIDE RECOVERY UNIT, LT		47	5,890	47	5,890	46	5,870
SULFUR PLANT, LT		44	9,090	44	9,090	43	9,060
WASTE WATER TREATING UNIT			22,970		22,970		22,970
SUBTOTAL PROCESS UNITS			220,780		220,780		198,150
CATALYSTS AND ROYALTIES			20,820		20,820		19,430
UTILITY UNITS			6,190		6,190		5,680
MISCELLANEOUS OFF SITES			56,740		56,740		50,960
CONTINGENCY AT 20%			60,910		60,910		54,840
TOTAL PLANT INVESTMENT			365,440		365,440		329,060
REVENUE FROM CONVENTIONAL PRODUCTS		UNITS/CD	$THOUS/A	UNITS/CD	$THOUS/A	UNITS/CD	$THOUS/A
GASOLINE,	$ 78.35/B	25,807	738,022	25,807	738,022	25,807	738,022
NO.2 FUEL OIL	$ 68.65/B	26,127	654,671				
PROPANE LPG,	$ 45.59/B	595	9,901	595	9,901	595	9,901
SULFUR,	$152.00/LT	37	2,053	37	2,053	37	2,053
AMMONIA,	$317.00/ST	122	13,093	122	13,093	122	13,093
GAS TO H2 PLANT FEED,	$ 56.03/B FOE	2,589	52,947	2,589	52,947	2,441	49,921
REFINERY FUEL GAS,	$ 56.03/B FOE	703	14,377	703	14,377	746	15,256
REFINERY FUEL OIL,	$ 56.03/B	3,170	64,830	3,170	64,830	2,776	56,772
TOTAL REVENUE FROM CONV. PRODUCTS			1,550,694		896,023		885,818
REVENUE FROM GAS TURBINE FUEL, $/B (2)				26,127	654,463	26,461	637,821
TOTAL REVENUE			1,550,694		1,550,486		1,523,639
COST OF CHARGE							
MI SHALE OIL,	$ 53.81/B (2)	50,000	982,118	50,000	982,118	50,000	982,118
ISOBUTANE,	$ 69.58/B	1,843	46,806	1,843	46,806	1,843	46,806
NORMAL BUTANE,	$ 60.00/B	1,723	37,734	1,723	37,734	1,723	37,734
TOTAL COST OF CHARGE			1,066,658		1,066,658		1,066,658
MANUFACTURING EXPENSE							
FUEL,	$ 56.03/B FOE	3,873	79,207	3,873	79,207	3,522	72,028
ELECTRIC POWER,	$ 0.0654/KWH	318,950	7,614	318,950	7,614	265,400	6,335
FRESH WATER,	$0.0686/THOUS GAL	5,506	138	5,506	138	5,224	131
SUBTOTAL UTILITIES			86,959		86,959		78,494
GAS TO H2 PLANT FEED,	$ 56.03/B FOE	2,589	52,947	2,589	52,947	2,441	49,921
CHEMICALS			1,307		1,099		1,072
TEL,	$ 9.984/THOUS CC	227	827	227	827	227	827
CATALYSTS			15,414		15,414		15,176
ROYALTY, DEMINERALIZING	$ 0.0056/B	50,000	102	50,000	102	50,000	102
LABOR BASED ITEMS (3)			1,454		1,454		728
INVESTMENT-BASED ITEMS (3)			34,373		34,373		30,922
TOTAL MANUFACTURING EXPENSE (3)			193,383		193,175		177,242
TOTAL EXPENSE			1,260,041		1,259,833		1,243,900
RETURN ON INCREMENTAL INVESTMENT AT 30% BEFORE TAXES			109,632		109,632		98,718
NET REVENUE, TOTAL REVENUE-TOTAL EXPENSE-RETURN			181,021		181,021		181,021
CALCULATED PRICE OF GAS TURBINE FUEL, $/B (2)				68.63		66.04	

1 INCREMENTAL OVER BASE CASE REFINERY, CASE 3.00.
2 CALCULATED TO PROVIDE SAME NET REVENUE AS IN BASE CASE REFINERY, CASE 3.00.
3 EXCLUDING INVESTMENT AND LABOR-BASED ITEMS IN BASE CASE REFINERY, CASE 3.00.

TABLE IV-1

SYNCRUDE PRICING CASES

ORIGINAL PAGE IS OF POOR QUALITY

ECONOMIC EVALUATION-U.S. GULF COAST-1985

CASE		1000		2000		3000		4000	
FEEDSTOCK		EASTERN COAL LIQUID (SRC-II)		WESTERN COAL LIQUID (H-COAL)		SURFACE-RETORTED SHALE OIL (PARAHO)		MODIFIED IN-SITU SHALE OIL	
DESCRIPTION		HIGH SEVERITY HYDROTREATING		MODERATE SEVERITY HYDROTREATING		HIGH SEVERITY HYDROTREATING PLUS FCC OF 640F+ BOTTOMS		HIGH SEVERITY HYDROTREATING PLUS FCC OF 640F+ BOTTOMS	
INVESTMENT, $THOUS (1984)		CAPACITY, UNITS/SD	INVESTMENT	CAPACITY, UNITS/SD	INVESTMENT	CAPACITY, UNITS/SD	INVESTMENT	CAPACITY, UNITS/SD	INVESTMENT
DESALTING UNIT, B CHARGE						58,820	2,070	58,820	2,070
HYDROTREATING UNIT, B CHARGE			-	74,000	170,870	58,820	154,230	58,820	122,910
NAPHTHA PRETREATING UNIT, B CHARGE		15,340	23,490			8,940	6,140	6,170	4,740
CATALYTIC REFORMING UNITS, B CHARGE		32,180	37,670	33,890	40,890	8,940	17,460	6,170	13,470
DISTILLATE HYDROTREATING UNIT, B CHARGE		47,460	199,430			23,220	17,840	27,780	20,380
FCC UNIT, B CHARGE						21,860	48,160	21,860	48,150
HF ALKYLATION UNIT, B ALKYLATE						5,500	19,100	5,510	19,120
GASOLINE SWEETENING UNIT, B CHARGE						13,080	1,100	13,900	1,110
STEAM REFORMING H2 PLANT, MSCF H2				[illegible] 460	23,680	1?3,700	96,540	74,640	55,090
H2S RECOVERY UNIT, LT H2S		32	5,230	4	2,650	59	6,?70	47	5,890
SULFUR PLANT, LT SULFUR		30	7,830	4	3,330	56	10,050	44	9,090
GAS PLANT, B CHARGE		?,600	1,090			5,500	2,940	2,860	2,120
PARTIAL OXIDATION H2 PLANT, MSCF H2		155,350	273,800						
SUBTOTAL PROCESS UNITS			549,340		[illegible]		381,980		304,140
CATALYSTS AND ROYALTIES			33,870		23,970		34,610		24,990
UTILITY FACILITIES			21,690		8,970		13,200		11,660
TANKAGE			20,040		24,110		20,860		20,900
MISCELLANEOUS OFF-SITES FACILITIES			196,030		94,070		138,540		112,120
CONTINGENCY AT 20%			164,340		80,110		117,840		94,760
TOTAL PLANT INVESTMENT			986,060		480,650		707,030		560,570
WORKING CAPITAL			83,700		87,220		74,030		70,690
TOTAL CAPITAL REQUIREMENT			1,069,760		567,870		781,060		639,260
RETURN FROM CONVENTIONAL PRODUCTS		UNITS/CD	$THOUS/YEAR	UNITS/CD	$THOUS/YEAR	UNITS/CD	$ THOUS/YEAR	UNITS/CD	$ THOUS/YEAR
GASOLINE, (1)	$ 70.35/B	34,330	881,764	40,859	1,168,475	30,543	816,266	25,807	738,022
C3 LPG,	$ 45.59/B	638	10,617			872	14,510	595	9,901
JET FUEL,	$ 70.34/B	31,17?	800,390					-	-
DIESEL FUEL,	$ 68.65/B			28,149	705,337	21,869	547,977	26,127	654,671
SULFUR,	$152.00/LT	22	1,228	3	[illegible]	47	2,600	37	2,053
AMMONIA,	$312.00/ST	11?	13,210	?0	5,270	208	23,687	120	13,666
REFINERY FUEL GAS,	$ 56.03/B FOE	1,5??	[illegible]	734	15,011	39	798	726	14,847
REFINERY FUEL OIL,	$ 56.03/B	[illegible]	[illegible]	2,752	56,?31	5,050	103,277	3,170	64,030
REFINERY GAS TO H2 PLANT,	$ 56.03/B FOE			910	18,610	4,253	86,978	2,566	52,477
REFINERY LIQ.TO H2 PLANT,	$ 56.03/B FOE	8,276	169,252						
TOTAL RETURN FROM PRODUCTS			2,055,547		1,766,150		1,596,101		1,550,467
COST OF CHARGE									
SYNCRUDE,	$(2)/B	66,600	1,255,762	66,600	1,524,448	50,000	983,517	50,000	1,057,904
ISOBUTANE,	$ 69.50/B					1,677	42,590	1,843	46,806
NORMAL BUTANE	$ 60.00/B	4,910	107,529	5,494	120,319	1,713	37,515	1,723	37,734
TOTAL COST OF CHARGE			1,363,291		1,644,767		1,063,622		1,142,524
MANUFACTURING EXPENSE									
REFINERY FUEL,	$56.03/B	4,343	80,019	3,406	71,292	5,089	104,075	3,896	79,677
POWER, PURCHASED,	$ 0.0654/KWH	547,340	13,066	197,070	4,704	364,550	8,702	318,950	7,614
WATER, FRESH,	$ 0.0606/THOUS GAL		132	2,601	65	6,155	154	5,506	138
SUBTOTAL UTILITIES			102,017		76,061		112,931		87,429
REFINERY LIQ.TO H2 PLANT, $56.03/ B		8,276	169,252	-		-		-	-
REFINERY GAS TO H2 PLANT, $56.03/ B FOE				910	18,610	4,253	86,970	2,566	52,477
CHEMICALS			4,289		445		1,458		1,307
CATALYSTS			9,899		8,778		24,324		15,414
ROYALTY			-				119		102
TEL,	$ 9.984/THOUS CC	344	1,254	446	1,625	245	892	227	827
INVESTMENT-BASED ITEMS			84,424		40,779		60,174		48,416
LABOR-BASED ITEMS		672	10,193	312	4,732	744	11,285	672	10,193
TOTAL MANUFACTURING EXPENSE			381,328		151,030		298,161		216,165
TOTAL EXPENSE EX SYNCRUDE			488,857		271,349		378,266		300,705
RETURN ON TOTAL CAPITAL AT 30% BEFORE TAXES			320,928		170,361		234,318		191,778
RETURN FROM CONVENTIONAL PRODUCTS LESS TOTAL EXPENSE EX SYNCRUDE LESS RETURN ON TOTAL CAPITAL			1,255,762		1,524,448		983,517		1,053,640
SYNCRUDE VALUE, $/B			51.66		62.71		53.89		[illegible].97

(1) 1985 POOL AVERAGE: 89.3 (R+M)/2 AT 0.27 CC/GAL TEL.
(2) CALCULATED TO GIVE 30% RETURN ON TOTAL CAPITAL.

TABLE IV-2

UPGRADING OF EASTERN COAL LIQUID (SRC-II) TO GAS TURBINE FUEL

ECONOMIC EVALUATION-U.S. GULF COAST-1985

CASE	1010		1011		1020		1030	
	HYDROTREATING OF SRC-II DISTILLATE AT MODERATE SEVERITY, STEAM REFORMING H2 PLANT		HYDROTREATING OF SRC-II DISTILLATE AT MODERATE SEVERITY, PARTIAL OXIDATION H2 PLANT		HYDROTREATING OF SRC-II DISTILLATE AT INTERMEDIATE SEVERITY, STEAM REFORMING H2 PLANT		HYDROTREATING OF SRC-II DISTILLATE AT HIGH SEVERITY, STEAM REFORMING H2 PLANT	
GAS TURBINE FUEL, B/CD	46,475		44,365		43,549		40,371	
NITROGEN, WT%	0.7		0.7		0.5		0.3	
VISCOSITY, CS @100F	3.6		3.6		2.9		2.45	
SULFUR, WT%	0.13		0.13		0.11		0.07	
VANADIUM, PPM			-					
GRAVITY, API	[illegible]		13.4		14.1		14.8	
INVESTMENT, $THOUS (1984)	CAPACITY, UNITS/SD	INVEST-MENT	CAPACITY, UNITS/SD	INVEST-MENT	CAPACITY, UNITS/SD	INVEST-MENT	CAPACITY, UNITS/SD	INVEST-MENT
NAPHTHA HYDROTREATING UNIT, B CHARGE	17,970	25,460	19,760	26,030	19,950	26,970	20,960	27,710
CATALYTIC REFORMING UNIT, B CHARGE	18,440	25,480	20,270	27,230	20,460	27,410	21,490	28,370
DISTILLATE HYDROTREATING UNIT, B CHARGE	56,770	113,810	53,750	109,310	56,770	119,580	56,770	169,460
PARTIAL OXIDATION H2 PLANT, MSCF H2		-	46,940	97,690	-	-	-	-
STEAM REFORMING H2 PLANT, MSCF H2	50,070	50,560	-	-	69,660	63,780	75,030	79,340
H2S RECOVERY UNIT, LT H2S	16	4,140	16	4,160	23	4,720	28	5,020
SULFUR PLANT, LT SULFUR	15	5,840	15	5,860	22	6,890	27	7,430
GAS PLANT, B CHARGE			1,650	1,400		-		-
SUBTOTAL PROCESS UNITS		225,290		272,480		249,350		317,330
CATALYSTS AND ROYALTIES		18,790		18,280		22,400		27,370
UTILITY FACILITIES		10,420		12,870		11,760		17,110
TANKAGE		18,190		18,410		18,150		18,000
MISCELLANEOUS OFF-SITES FACILITIES		84,550		101,450		92,990		117,360
CONTINGENCY AT 20%		71,450		84,640		78,930		99,430
TOTAL PLANT INVESTMENT		428,690		507,030		473,580		596,600
WORKING CAPITAL		68,750		67,030		71,890		79,490
TOTAL CAPITAL REQUIREMENT		497,440		574,060		545,470		676,090
RETURN FROM CONVENTIONAL PRODUCTS	UNITS/CD	$THOUS/YEAR	UNITS/CD	$THOUS/YEAR	UNITS/CD	$ THOUS/YEAR	UNITS/CD	$THOUS/YEAR
GASOLINE, $ (1)/B	16,527	480,899	18,679	543,091	18,157	528,726	18,989	553,231
C3 LPG, $ 45.59/B		-	241	4,010	-	-	-	-
SULFUR, $152.00/LT	13	721	13	721	20	1,110	24	1,332
AMMONIA, $312.00/ST	78	8,883	81	9,224	100	11,388	122	13,893
REFINERY FUEL GAS, $ 56.03/B FOE	1,073	21,944	762	15,584	1,134	23,191	1,397	28,570
REFINERY FUEL OIL, $ 56.03/B	2,186	44,706	1,713	35,032	2,752	56,281	3,989	81,579
REFINERY LIQ.TO H2 PLANT, $ 56.03/B	2,303	47,099	2,712	55,463	3,222	65,893	4,405	90,086
TOTAL RETURN FROM CONVENTIONAL PRODUCTS		604,252		663,075		686,589		768,691
RETURN FROM GAS TURBINE FUEL, $(2)/B	46,475	968,504	44,365	935,125	43,549	939,358	40,371	969,511
TOTAL RETURN FROM PRODUCTS		1,572,756		1,598,200		1,625,947		1,738,202
COST OF CHARGE (SRC-II LIQUID), $51.70/B	66,600	1,256,775	66,600	1,256,775	66,600	1,256,775	66,600	1,256,775
MANUFACTURING EXPENSE								
REFINERY FUEL, $56.03/B	3,259	66,650	2,475	50,616	3,886	79,472	5,386	110,149
POWER, PURCHASED, $ 0.0654/KWH	169,310	4,042	210,454	5,024	200,000	4,774	337,190	8,049
WATER, FRESH, $ 0.0686/THOUS GAL	1,802	45	2,070	52	2,144	54	3,828	96
SUBTOTAL UTILITIES		70,737		55,692		84,300		118,294
REFINERY LIQ.TO H2 PLANT, $56.03/ B FOE	2,303	47,099	2,712	55,463	3,222	65,893	4,405	90,086
CHEMICALS		348		1,301		463		673
CATALYSTS		6,646		6,254		9,168		13,330
ROYALTY		-		-		-		-
INVESTMENT-BASED ITEMS		36,459		43,340		40,247		50,757
LABOR-BASED ITEMS	360	5,460	456	6,917	360	5,460	360	5,460
TOTAL MANUFACTURING EXPENSE		166,749		168,967		205,531		278,690
TOTAL EXPENSE		1,423,524		1,425,742		1,462,306		1,535,375
RETURN ON TOTAL CAPITAL AT 30% BEFORE TAXES		149,232		172,458		163,641		202,827
TOTAL EXPENSE PLUS RETURN ON INVESTMENT LESS RETURN FROM CONVENTIONAL PRODUCTS		968,504		935,125		939,358		969,511
GAS TURBINE FUEL COST, $/B		57.09		57.75		59.10		65.79

(1) THE GASOLINE PRICE IS ADJUSTED FOR OCTANE LEVEL ON THE BASIS OF $78.35/B FOR 87 (R+M)/2 AND $82.35/B FOR 93 (R+M)/2
(2) CALCULATED TO GIVE 30% RETURN ON TOTAL CAPITAL.

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TABLE IV-3

UPGRADING OF WESTERN COAL LIQUID (H-COAL) TO GAS TURBINE FUEL

ECONOMIC EVALUATION U.S. GULF COAST 198[illegible]

CASE		2010		2030	
		HYDROTREATING OF NAPHTHA ONLY, RAW 350+ TO GAS TURBINE FUEL		WHOLE LIQUID HYDROTREATING AT MODERATE SEVERITY	
GAS TURBINE FUEL, B/CD		37,181		20,149	
NITROGEN, WT%		0.26			
VISCOSITY, CS @100F		1.7		3.6	
SULFUR, WT%		0.07			
VANADIUM, PPM					
GRAVITY, API		27.0		32.3	
INVESTMENT, $THOUS (1984)		CAPACITY, UNITS/SD	INVESTMENT	CAPACITY, UNITS/SD	INVESTMENT
DISTILLATION UNIT, B CHARGE		70,850	[illegible]		
HYDROTREATING UNIT, B CHARGE				74,000	178,870
NAPHTHA PRETREATING UNIT, B CHARGE		23,030	11,970		
CATALYTIC REFORMING UNIT, B CHARGE		24,300	34,080	33,890	40,890
STEAM REFORMING H2 PLANT, MSCF H2				22,460	23,680
H2S RECOVERY UNIT, LT H2S		3	2,530	4	2,650
SULFUR PLANT, LT SULFUR		3	3,130	3	3,330
GAS PLANT, B CHARGE		1,230	1,270		
SUBTOTAL PROCESS UNITS			[illegible]		[illegible]
CATALYSTS AND ROYALTIES			8,400		23,970
UTILITY FACILITIES			7,000		8,970
STORAGE			17,520		21,540
MISCELLANEOUS OFF-SITES FACILITIES			35,720		93,220
CONTINGENCY AT 20%			30,280		79,420
TOTAL PLANT INVESTMENT			181,680		476,540
WORKING CAPITAL			[illegible]		83,030
TOTAL CAPITAL REQUIREMENT			[illegible]		559,570
RETURN FROM CONVENTIONAL PRODUCTS		UNITS/CD	$THOUS/YEAR	UNITS/CD	$THOUS/YEAR
GASOLINE,	$ [illegible]/B	26,399	[illegible]	55,365	[illegible]
C3 LPG,	$ 41.59/B	[illegible]	4,545		
SULFUR,	$152.00/LT	3	166	3	166
AMMONIA,	$31[illegible].00/ST	17	1,936	20	2,278
REFINERY FUEL GAS,	$ 56.03/B FOE	1,395	[illegible]	[illegible]	[illegible]
REFINERY FUEL OIL,	$ 56.05/B	1,111	[illegible]	[illegible]	[illegible]
REFINERY GAS TO H2 PLANT,	$ [illegible].05/B FOE			910	18,610
TOTAL RETURN FROM CONVENTIONAL PRODUCTS			[illegible]		[illegible]
RETURN FROM GAS TURBINE FUEL, $[illegible]/B		37,181	[illegible]	20,149	[illegible]
TOTAL RETURN FROM PRODUCTS			[illegible]		1,831,093
COST OF CHARGE - H-COAL LIQUID @ $62.20/B		66,000	[illegible]	66,000	1,524,174
MANUFACTURING EXPENSE					
REFINERY FUEL,	$56.05/B	3,009	[illegible]	5,406	[illegible]
POWER PURCHASED,	$ 0.0654/KWH	100,786	2,406	[illegible]	4,704
WATER, FRESH,	$ 0.0686/THOUS GAL	1,230	31	[illegible]	65
SUBTOTAL UTILITIES			[illegible]		[illegible]
REFINERY GAS TO H2 PLANT, $56.05/B FOE				910	18,610
CHEMICALS			242		416
CATALYSTS			226		8,778
INVESTMENT-BASED ITEMS			15,295		40,451
LABOR-BASED ITEMS		316	3,276	312	4,732
TOTAL MANUFACTURING EXPENSE			83,013		149,048
TOTAL EXPENSE			1,607,187		1,673,222
RETURN ON TOTAL CAPITAL AT 30% BEFORE TAXES			77,073		167,871
TOTAL EXPENSE PLUS RETURN ON INVESTMENT LESS RETURN FROM CONVENTIONAL PRODUCTS			862,090		239,066
GAS TURBINE FUEL COST, $/B			63.52		71.93

(1) THE GASOLINE PRICE IS ADJUSTED FOR OCTANE LEVEL ON THE BASIS OF $78.35/B FOR 87 (R+M)/2 AND $82.35/B FOR 93 (R+M)/2.
(2) CALCULATED TO GIVE 30% RETURN ON TOTAL CAPITAL.

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TABLE IV-4

UPGRADING OF SURFACE-RETORTED (PARAHO) SHALE OIL TO GAS TURBINE FUEL

ECONOMIC EVALUATION-U.S. GULF COAST-1985

CASE	3010		3011		3020		3030	
	HYDROTREATING AT MODERATE SEVERITY, DIST. TO DIESEL FUEL, STEAM REFORMING H2 PLANT		HYDROTREATING AT MODERATE SEVERITY, DIST. TO DIESEL FUEL, PARTIAL OXIDATION H2 PLANT		HYDROTREATING AT INTERMEDIATE SEVERITY, DIST. TO DIESEL FUEL, STEAM REFORMING H2 PLANT		HYDROTREATING AT HIGH SEVERITY, DIST. TO DIESEL FUEL, STEAM REFORMING H2 PLANT	
GAS TURBINE FUEL, B/CD	22,639		21,548		20,616		17,626	
NITROGEN, WT%	0.5		0.5		0.3		0.19	
VISCOSITY, CS @100F			-		-		-	
SULFUR, WT%	0.05		0.05		0.04		0.012	
VANADIUM, PPM			-		-		-	
GRAVITY, API	25.0		25.0		27.0		29.0	
INVESTMENT, $THOUS (1984)	CAPACITY, UNITS/SD	INVEST-MENT	CAPACITY, UNITS/SD	INVEST-MENT	CAPACITY, UNITS/SD	INVEST-MENT	CAPACITY, UNITS/SD	INVEST-MENT
DESALTING UNIT, B CHARGE	58,820	2,070	58,820	2,670	58,820	2,070	58,820	2,070
HYDROTREATING UNIT, B CHARGE	58,820	150,300	53,200	139,260	58,820	155,240	58,820	154,340
CATALYTIC REFORMING UNIT, B CHARGE	-	-	4,130	13,740	-	-	-	-
DISTILLATE HYDROTREATING UNIT, B CHARGE	27,530	20,240	24,900	18,790	29,670	21,390	31,150	22,180
PARTIAL OXIDATION H2 PLANT, MSCF H2	-	-	87,330	148,080	-	-	-	-
STEAM REFORMING H2 PLANT, MSCF H2	100,960	101,710	-	-	117,320	113,040	133,890	124,040
H2S RECOVERY UNIT, LT H2S	58	6,320	53	6,120	58	6,320	59	6,350
SULFUR PLANT, LT SULFUR	55	9,950	50	9,550	55	9,950	56	10,010
GAS PLANT, B CHARGE	-	-	2,610	2,030	-	-	-	-
SUBTOTAL PROCESS UNITS		290,590		339,640		308,010		318,990
CATALYSTS AND ROYALTIES		14,650		12,660		16,510		30,650
UTILITY FACILITIES		10,940		13,770		11,310		11,660
TANKAGE		15,730		16,230		16,250		16,530
MISCELLANEOUS OFF-SITES FACILITIES		105,650		123,090		111,750		115,610
CONTINGENCY AT 20%		87,510		101,080		92,770		98,690
TOTAL PLANT INVESTMENT		525,070		606,470		556,600		592,130
WORKING CAPITAL		59,360		55,220		60,910		65,090
TOTAL CAPITAL REQUIREMENT		584,430		661,690		617,510		657,220
RETURN FROM CONVENTIONAL PRODUCTS	UNITS/CD	$THOUS/YEAR	UNITS/CD	$THOUS/YEAR	UNITS/CD	$THOUS/YEAR	UNITS/CD	$THOUS/YEAR
GASOLINE, $ (1)/B			3,583	105,871	-	-	-	-
C3 LPG, $ 45.59/B			480	7,992	-	-	-	-
NAPHTHA, $ 68.65/B	103	2,589			384	9,619	1,929	48,345
DIESEL FUEL, $ 68.65/B	23,699	593,825	21,431	537,008	25,435	637,319	26,588	666,225
SULFUR, $152.00/LT	47	2,582	42	2,335	47	2,582	47	2,620
AMMONIA, $312.00/ST	162	18,479	147	16,711	183	20,893	207	23,595
REFINERY FUEL GAS, $ 56.03/B FOE	1,412	28,886	1,187	24,283	2,126	43,469	2,308	47,208
REFINERY FUEL OIL, $ 56.03/B	2,039	41,693	768	15,716	1,661	33,969	1,813	37,071
REFINERY LIQ. TO H2 PLANT, $ 56.03/B	4,073	83,297	4,784	97,837	4,750	97,142	5,503	112,542
TOTAL RETURN FROM CONVENTIONAL PRODUCTS		771,351		807,753		844,993		937,606
RETURN FROM GAS TURBINE FUEL, $/B (2)	22,639	607,034	21,548	588,768	20,616	568,689	17,626	527,993
TOTAL RETURN FROM PRODUCTS		1,378,385		1,396,521		1,413,682		1,465,599
COST OF CHARGE (PARAHO SHALE OIL), $53.90/B	50,000	983,675	50,000	983,675	50,000	983,675	50,000	983,675
MANUFACTURING EXPENSE								
REFINERY FUEL, $56.03/B	3,451	70,579	1,955	39,999	3,787	77,438	4,121	84,279
POWER, PURCHASED, $ 0.0654/KWH	308,555	7,366	353,062	8,428	328,501	7,842	347,715	8,300
WATER, FRESH, $ 0.0686/THOUS GAL	4,135	104	4,296	108	4,320	108	4,503	113
SUBTOTAL UTILITIES		78,049		48,535		85,388		92,692
REFINERY LIQ. TO H2 PLANT, $56.03/B	4,073	83,297	4,784	97,837	4,750	97,142	5,503	112,542
CHEMICALS		1,153		2,581		1,209		1,255
CATALYSTS		6,297		5,190		7,749		22,339
ROYALTY		119		119		119		119
INVESTMENT-BASED ITEMS		45,004		52,121		47,685		50,349
LABOR-BASED ITEMS	360	5,462	528	8,008	360	5,462	360	5,462
TOTAL MANUFACTURING EXPENSE		219,381		214,399		244,754		284,758
TOTAL EXPENSE		1,203,056		1,198,014		1,228,429		1,268,433
RETURN ON TOTAL CAPITAL AT 30% BEFORE TAXES		175,329		198,507		185,253		191,166
TOTAL EXPENSE PLUS RETURN ON INVESTMENT LESS RETURN FROM CONVENTIONAL PRODUCTS		607,034		588,768		568,689		527,993
GAS TURBINE FUEL COST, $/B		73.46		74.86		75.57		82.07

(1) THE GASOLINE PRICE IS ADJUSTED FOR OCTANE ON THE BASIS OF $78.35/B FOR 87 (R+M)/2 AND $82.35/B FOR 93 (R+M)/2.
(2) CALCULATED TO GIVE 30% RETURN ON TOTAL CAPITAL.

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TABLE IV-5

UPGRADING OF SURFACE-RETORTED (PARAHO) SHALE OIL TO GAS TURBINE FUEL

ECONOMIC EVALUATION-U.S. GULF COAST-1985

CASE	301A		302A		303A	
	HYDROTREATING AT MODERATE SEVERITY, 350F PLUS TO GAS TURBINE FUEL		HYDROTREATING AT INTERMEDIATE SEVERITY, 350F PLUS TO GAS TURBINE FUEL		HYDROTREATING AT HIGH SEVERITY, 350F PLUS TO GAS TURBINE FUEL	
GAS TURBINE FUEL, B/CD	46,341		46,155		44,448	
NITROGEN, WT%	0.54		0.34		0.108	
VISCOSITY, CS @100F	-		-		-	
SULFUR, WT%	0.028		0.021		0.007	
VANADIUM, PPM	-		-		-	
GRAVITY, API	29.9		32.8		34.2	
INVESTMENT, $THOUS (1984)	CAPACITY, UNITS/SD	INVESTMENT	CAPACITY, UNITS/SD	INVESTMENT	CAPACITY, UNITS/SD	INVESTMENT
DESALTING UNIT, B CHARGE	58,820	2,070	58,820	2,070	58,820	2,070
HYDROTREATING UNIT, B CHARGE	58,820	150,300	58,820	155,240	58,820	154,340
STEAM REFORMING H2 PLANT, MSCF H2	89,590	76,120	109,230	107,500	128,860	120,750
H2S RECOVERY UNIT, LT H2S	58	6,320	58	6,320	59	6,350
SULFUR PLANT, LT SULFUR	55	9,950	55	9,950	56	10,000
SUBTOTAL PROCESS UNITS		244,760		281,080		293,510
CATALYSTS AND ROYALTIES		13,070		14,910		29,050
UTILITY FACILITIES		9,520		9,880		10,590
TANKAGE		15,360		14,780		15,530
MISCELLANEOUS OFF-SITES FACILITIES		89,790		101,810		106,440
CONTINGENCY AT 20%		74,500		84,490		91,020
TOTAL PLANT INVESTMENT		447,000		506,950		546,140
WORKING CAPITAL		56,400		58,400		63,420
TOTAL CAPITAL REQUIREMENT		503,400		565,350		609,560
RETURN FROM CONVENTIONAL PRODUCTS	UNITS/CD	$THOUS/YEAR	UNITS/CD	$THOUS/YEAR	UNITS/CD	$THOUS/YEAR
NAPHTHA, $ 68.65/B	562	14,076	711	17,826	2,136	53,521
SULFUR, $152.00/LT	47	2,582	47	2,582	47	2,620
AMMONIA, $312.00/ST	162	18,479	183	20,893	207	23,595
REFINERY FUEL GAS, $ 56.03/B FOE	1,192	24,371	1,962	40,115	2,213	45,251
REFINERY FUEL OIL, $ 56.03/B	1,739	35,570	1,344	27,479	1,469	30,039
REFINERY LIQ.TO H2 PLANT, $ 56.03/B	3,614	73,910	4,423	90,455	5,297	108,329
TOTAL RETURN FROM CONVENTIONAL PRODUCTS		168,988		199,350		263,355
RETURN FROM GAS TURBINE FUEL, $/B (2)	46,341	1,154,829	46,155	1,175,152	44,448	1,168,456
TOTAL RETURN FROM PRODUCTS		1,323,817		1,374,502		1,431,811
COST OF CHARGE (PARAHO SHALE OIL), $53.50/B	50,000	983,675	50,000	983,675	50,000	983,675
MANUFACTURING EXPENSE						
REFINERY FUEL, $56.03/B	2,931	59,941	3,306	67,594	3,682	75,290
POWER, PURCHASED, $ 0.0654/KWH	252,305	6,023	272,066	6,494	291,956	6,969
WATER, FRESH, $ 0.0686/THOUS GAL	3,770	94	3,967	99	4,168	104
SUBTOTAL UTILITIES		66,058		74,187		82,363
REFINERY LIQ.TO H2 PLANT, $56.03/ B	3,614	73,910	4,423	90,455	5,297	108,329
CHEMICALS		1,098		1,164		1,221
CATALYSTS		6,025		7,487		22,090
ROYALTY		119		119		119
INVESTMENT-BASED ITEMS		38,271		43,441		46,413
LABOR-BASED ITEMS	240	3,641	288	4,369	312	4,733
TOTAL MANUFACTURING EXPENSE		189,122		221,222		265,268
TOTAL EXPENSE		1,172,797		1,204,897		1,248,943
RETURN ON TOTAL CAPITAL AT 30% BEFORE TAXES		151,020		169,605		182,868
TOTAL EXPENSE PLUS RETURN ON INVESTMENT LESS RETURN FROM CONVENTIONAL PRODUCTS		1,154,829		1,175,152		1,168,456
GAS TURBINE FUEL COST, $/B		68.27		69.76		72.02

(1) THE GASOLINE PRICE IS ADJUSTED FOR OCTANE LEVEL ON THE BASIS OF $78.35/B FOR 87 (R+M)/2 AND $82.35/B FOR 93 (R+M)/2.
(2) CALCULATED TO GIVE 30% RETURN ON TOTAL CAPITAL.

ORIGINAL PAGE IS
OF POOR QUALITY

TABLE IV-6

UPGRADING OF SURFACE RETORTED (PARAHO) SHALE OIL TO GAS TURBINE FUEL

ECONOMIC EVALUATION-U.S. GULF COAST-1985

CASE		3040		3050		3060	
		COKING OF PARAHO SHALE OIL AND HYDROTREATING OF COKER DISTILLATE		COKING OF PARAHO SHALE OIL AND HYDROTREATING OF COKER DISTILLATE		COKING OF PARAHO SHALE OIL AND HYDROTREATING OF COKER DISTILLATE PLUS HYDROTREATING OF HYDROTREATED DISTILLATE	
GAS TURBINE FUEL, B/CD		28,425		28,868		29,431	
NITROGEN, WT%		0.5		0.3		0.06	
VISCOSITY, CS @100F		-		-		-	
SULFUR, WT%		0.010		0.008		0.0001	
VANADIUM, PPM							
GRAVITY, API		37.0		39.0		40.7	
INVESTMENT, $THOUS (1984)		CAPACITY, UNITS/SD	INVEST-MENT	CAPACITY, UNITS/SD	INVEST-MENT	CAPACITY, UNITS/SD	INVEST-MENT
DESALTING UNIT, B CHARGE		55,560	2,000	55,560	2,070	55,560	2,000
DELAYED COKING UNIT, B CHARGE		55,560	60,780	55,560	60,780	55,560	60,780
HYDROTREATING UNIT, B CHARGE		44,910	91,020	44,910	92,610	44,910	94,730
NAPHTHA PRETREATING AND CATALYTIC REFORMING UNITS, B CHARGE		5,310	16,410	7,010	19,930	8,850	23,470
DISTILLATE HYDROTREATING UNIT, B CHARGE		-	-	-	-	32,650	22,960
STEAM REFORMING H2 PLANT, MSCF H2		49,900	41,510	53,410	43,540	63,520	49,190
H2S RECOVERY UNIT, LT H2S		48	5,930	48	5,930	47	5,890
SULFUR PLANT, LT SULFUR		45	9,170	45	9,180	44	9,110
GAS PLANT, B CHARGE		1,300	1,440	1,850	1,700	2,530	1,990
SUBTOTAL PROCESS UNITS			228,260		235,670		270,120
CATALYSTS AND ROYALTIES			12,630		14,220		17,760
UTILITY FACILITIES			7,980		8,150		9,530
TANKAGE			17,570		17,720		19,350
MISCELLANEOUS OFF-SITES FACILITIES			84,520		87,090		99,570
CONTINGENCY AT 20%			70,190		72,570		83,270
TOTAL PLANT INVESTMENT			421,150		435,420		499,600
WORKING CAPITAL			60,590		61,620		65,410
TOTAL CAPITAL REQUIREMENT			481,740		497,040		565,010
RETURN FROM CONVENTIONAL PRODUCTS		UNITS/CD	$THOUS/YEAR	UNITS/CD	$THOUS/YEAR	UNITS/CD	$ THOUS/YEAR
GASOLINE,	$ (1)/B	5,034	148,875	6,796	199,813	8,310	244,520
C3 LPG,	$ 45.57/B	322	5,361	408	6,783	543	9,039
COKE,	$ 40.00/ST	1,551	22,645	1,551	22,645	1,551	22,645
RESIDUAL FUEL,	$ 56.03/B	5,457	111,614	3,475	71,073	952	19,471
SULFUR,	$152.00/LT	40	2,240	40	2,254	40	2,199
AMMONIA,	$312.00/ST	112	12,727	128	14,608	146	16,647
REFINERY FUEL GAS,	$ 56.03/B FOE	1,629	33,313	1,799	36,775	1,916	39,186
REFINERY FUEL OIL,	$ 56.03/B	1,880	38,443	1,891	38,672	2,400	49,074
REFINERY GAS TO H2 PLANT,	$ 56.03/B FOE	1,783	36,464	1,908	39,027	2,270	46,424
TOTAL RETURN FROM CONVENTIONAL PRODUCTS			411,682		431,640		449,213
RETURN FROM GAS TURBINE FUEL, $(2)/B		28,425	881,940	28,868	875,181	29,431	907,804
TOTAL RETURN FROM PRODUCTS			1,293,630		1,306,821		1,357,017
COST OF CHARGE (PARAHO SHALE OIL),	$53.90/B	50,000	983,675	50,000	983,675	50,000	983,675
MANUFACTURING EXPENSE							
REFINERY FUEL,	$56.03/B	3,509	71,756	3,690	75,447	4,316	88,260
POWER, PURCHASED,	$ 0.0654/KWH	278,675	5,652	286,354	6,836	356,231	8,504
WATER, FRESH,	$ 0.0686/THOUS GAL	3,759	94	3,840	96	4,277	107
SUBTOTAL UTILITIES			78,502		82,379		96,871
REFINERY GAS TO H2 PLANT,	$56.03/B FOE	1,783	36,464	1,908	39,027	2,270	46,424
CHEMICALS			562		577		625
CATALYSTS			6,119		7,072		8,762
ROYALTY			119		119		119
INVESTMENT-BASED ITEMS			36,023		37,216		42,666
LABOR-BASED ITEMS		504	7,644	504	7,644	552	8,372
TOTAL MANUFACTURING EXPENSE			165,433		174,034		203,839
TOTAL EXPENSE			1,149,108		1,157,709		1,187,514
RETURN ON TOTAL CAPITAL AT 30% BEFORE TAXES			144,522		149,112		169,503
TOTAL EXPENSE PLUS RETURN ON INVESTMENT LESS RETURN FROM CONVENTIONAL PRODUCTS			881,948		875,181		907,804
GAS TURBINE FUEL COST, $/B			85.01		83.06		84.51

(1) THE GASOLINE PRICE IS ADJUSTED FOR OCTANE LEVEL ON THE BASIS OF $78.35/B FOR 87 (R+M)/2 AND $82.35/B FOR 93 (R+M)/2.
(2) CALCULATED TO GIVE 30% RETURN ON TOTAL CAPITAL.

TABLE IV-7

UPGRADING OF MODIFIED IN-SITU SHALE OIL TO GAS TURBINE FUEL

ECONOMIC EVALUATION-U.S. GULF COAST-1985

CASE	4020	402A
	HYDROTREATING AT INTERMEDIATE SEVERITY PLUS HYDROTREATING OF DIESEL FUEL	HYDROTREATING AT INTERMEDIATE SEVERITY, 350F+ PRODUCT TO GAS TURBINE FUEL
GAS TURBINE FUEL, B/CD	22,086	46,253
NITROGEN, WT%	0.30	0.30
VISCOSITY, CS @100F	NA	NA
SULFUR, WT%	0.040	0.025
VANADIUM, PPM	<0.1	<0.1
GRAVITY, API	27.0	32.0

INVESTMENT, $THOUS (1984)	CAPACITY, UNITS/SD	INVESTMENT	CAPACITY, UNITS/SD	INVESTMENT
DESALTING UNIT, B CHARGE	58,820	2,070	58,820	2,070
HYDROTREATING UNIT, B CHARGE	58,820	122,910	58,820	122,910
DISTILLATE HYDROTREATING UNIT, B CHARGE	28,080	20,540	-	-
STEAM REFORMER H2 PLANT, MSCF H2	77,620	68,820	69,960	63,970
H2S RECOVERY UNIT, LT H2S	46	5,870	46	5,870
SULFUR PLANT, LT SULFUR	43	9,060	43	9,060
GAS PLANT, B CHARGE	-	-	-	-
SUBTOTAL PROCESS UNITS		229,270		203,880
CATALYSTS AND ROYALTIES		20,940		19,430
UTILITY FACILITIES		10,050		9,050
TANKAGE		16,150		14,700
MISCELLANEOUS OFF-SITES FACILITIES		85,070		75,800
CONTINGENCY AT 20%		72,300		64,570
TOTAL PLANT INVESTMENT		433,780		387,430
WORKING CAPITAL		61,350		59,100
TOTAL CAPITAL REQUIREMENT		495,130		446,530

RETURN FROM CONVENTIONAL PRODUCTS		UNITS/CD	$THOUS/YEAR	UNITS/CD	$THOUS/YEAR
NAPHTHA,	$ 68.65/ST	1,322	33,126	1,632	40,893
DIESEL FUEL,	$ 68.65/B	24,066	603,028	-	-
SULFUR,	$152.00/LT	37	2,053	37	2,053
AMMONIA,	$312.00/ST	119	12,527	119	12,527
REFINERY FUEL GAS,	$ 56.03/B FOE	1,183	24,173	1,027	21,003
REFINERY FUEL OIL,	$ 56.03/B	1,798	36,771	1,498	30,636
REFINERY LIQ.TO H2 PLANT,	$ 56.03/B FOE	3,143	64,277	2,833	57,938
TOTAL RETURN FROM CONVENTIONAL PRODUCTS			775,975		165,050
RETURN FROM GAS TURBINE FUEL, $(2)/B		22,086	619,201	46,253	1,193,616
TOTAL RETURN FROM PRODUCTS			1,395,176		1,358,666
COST OF CHARGE (MIS SHALE OIL),	$58.00/B	50,000	1,058,500	50,000	1,058,500
MANUFACTURING EXPENSE					
REFINERY FUEL,	$56.03/B	2,981	60,964	2,525	51,639
POWER, PURCHASED,	$ 0.0654/KWH	284,140	6,783	230,730	5,508
WATER, FRESH,	$ 0.0686/THOUS GAL	3,879	97	3,534	88
SUBTOTAL UTILITIES			67,844		57,235
REFINERY LIQ.TO H2 PLANT,	$56.03/ B	3,143	64,277	2,833	57,938
CHEMICALS			1,029		987
CATALYSTS			13,635		13,387
ROYALTY			119		119
INVESTMENT-BASED ITEMS			36,865		32,901
LABOR-BASED ITEMS		288	4,368	240	3,640
TOTAL MANUFACTURING EXPENSE			188,137		166,207
TOTAL EXPENSE			1,246,637		1,224,707
RETURN ON TOTAL CAPITAL AT 30% BEFORE TAXES			148,539		133,959
TOTAL EXPENSE PLUS RETURN ON INVESTMENT LESS RETURN FROM CONVENTIONAL PRODUCTS			619,201		1,193,616
GAS TURBINE FUEL COST, $/B			76.81		70.70

(1) THE GASOLINE PRICE IS ADJUSTED FOR OCTANE LEVEL ON THE BASIS OF $78.35/B FOR 87 (R+M)/2 AND $82.35/B FOR 93 (R+M)/2.
(2) CALCULATED TO GIVE 39% RETURN ON TOTAL CAPITAL.

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TABLE IV-8

UPGRADING OF LOW-SULFUR PETROLEUM RESIDUAL OIL TO GAS TURBINE FUEL

ECONOMIC EVALUATION-U.S. GULF COAST-1985

CASE	5010		5020		5030		5040	
	HYDROTREATING OF VACUUM BOTTOMS AT MODERATE SEVERITY		HYDROTREATING OF VACUUM BOTTOMS AT INTERMEDIATE SEVERITY		HYDROTREATING OF VACUUM BOTTOMS AT HIGH SEVERITY		DELAYED COKING OF VACUUM BOTTOMS PLUS HYDROTREATING OF COKER DISTILLATE	
GAS TURBINE FUEL, B/CD	17,544		17,233		17,096		9,523	
NITROGEN, WT%	0.09		0.09		0.09		0.09	
VISCOSITY, CS @100F	1,100		1,100		1,100		1.7	
SULFUR, WT%	0.26		0.23		0.19		0.05	
VANADIUM, PPM	1.3		0.5		0.05		-	
GRAVITY, API	22.4		22.6		23.0		37.2	
INVESTMENT, $THOUS (1984)	CAPACITY, UNITS/SD	INVEST-MENT	CAPACITY, UNITS/SD	INVEST-MENT	CAPACITY, UNITS/SD	INVEST-MENT	CAPACITY, UNITS/SD	INVEST-MENT
DELAYED COKING UNIT, B CHARGE	-	-	-	-	-	-	13,300	25,410
HYDROTREATING UNIT, B CHARGE	13,420	23,920	13,220	25,270	13,190	25,950	9,910	10,260
PARTIAL OXIDATION H2 PLANT, MSCF H2	5,720	23,850	6,170	25,090	6,690	26,480	-	-
STEAM REFORMING H2 PLANT, MSCF H2		-	-	-	-	-	6,400	9,790
H2S RECOVERY UNIT, LT H2S	17	4,250	17	4,280	19	4,420	14	3,970
SULFUR PLANT, LT SULFUR	16	6,040	16	6,090	18	6,340	13	5,530
SUBTOTAL PROCESS UNITS		58,060		60,730		63,190		54,960
CATALYSTS AND ROYALTIES		3,300		3,540		3,690		1,250
UTILITY FACILITIES		4,030		4,100		4,193		3,370
TANKAGE		5,810		5,760		5,730		4,210
MISCELLANEOUS OFF-SITES FACILITIES		22,610		23,510		24,350		20,830
CONTINGENCY AT 20%		18,760		19,530		20,230		16,920
TOTAL PLANT INVESTMENT		112,570		117,170		121,380		101,540
WORKING CAPITAL		16,900		16,660		16,630		12,140
TOTAL CAPITAL REQUIREMENT		129,470		133,830		138,010		113,680
RETURN FROM CONVENTIONAL PRODUCTS	UNITS/CD	$THOUS/YEAR	UNITS/CD	$THOUS/YEAR	UNITS/CD	$ THOUS/YEAR	UNITS/CD	$THOUS/YEAR
COKE, $ 40.00/ST		-		-	-	-	662	41,802
SULFUR, $152.00/LT	14	777	15	832	16	888	12	656
FUEL GAS TO SALES, $ 56.03/B FOE	-		-	-	-	-	372	7,608
REFINERY FUEL GAS, $ 56.03/B FOE	84	1,718	92	1,881	100	2,045	630	12,884
REFINERY FUEL OIL, $ 56.03/B	166	3,395	161	3,293	163	3,333	-	-
REFINERY GAS TO H2 PLANT, $ 56.03/B			-		-		226	4,622
VTB TO H2 PLANT, $ 56.03/B	307	6,278	333	6,810	360	7,362	-	-
TOTAL RETURN FROM CONVENTIONAL PRODUCTS		12,168		12,816		13,628		67,582
RETURN FROM GAS TURBINE FUEL, $(1)/B	17,544	394,425	17,233	388,173	17,096	386,510	9,523	223,151
TOTAL RETURN FROM PRODUCTS		406,593		400,989		400,138		290,733
COST OF CHARGE								
SO. LOUISIANA VTB, $49.62/B (2)	12,655	226,427	12,655	226,427	12,659	226,498	12,500	223,654
NO. 2 FUEL OIL, $68.65/B	4,477	112,181	4,148	103,937	4,007	100,404	-	-
TOTAL COST OF CHARGE	17,132	338,608	16,803	330,364	16,666	326,902	12,500	223,654
MANUFACTURING EXPENSE								
REFINERY FUEL, $56.03/B	250	5,113	253	5,174	263	5,378	630	12,884
POWER, PURCHASED, $ 0.0654/KWH	65,190	1,556	67,800	1,618	70,950	1,694	71,970	1,718
WATER, FRESH, $ 0.0686/THOUS GAL	372	9	395	10	423	11	334	8
SUBTOTAL UTILITIES		6,670		6,802		7,083		14,610
REFINERY LIQ. TO H2 PLANT, $56.03/ B FOE	307	6,278	333	6,810	360	7,362	-	-
REFINERY GAS TO H2 PLANT, $56.03/ B FOE		-		-			226	4,622
CHEMICALS		235		250		270		79
CATALYSTS		919		1,165		1,307		209
INVESTMENT-BASED ITEMS		9,574		9,989		10,351		8,723
LABOR-BASED ITEMS	360	5,460	360	5,460	360	5,460	312	4,732
TOTAL MANUFACTURING EXPENSE		29,144		30,476		31,833		32,975
TOTAL EXPENSE		367,752		360,840		358,735		256,629
RETURN ON TOTAL CAPITAL AT 30% BEFORE TAXES		38,841		40,149		41,403		34,104
TOTAL EXPENSE PLUS RETURN ON INVESTMENT LESS RETURN FROM CONVENTIONAL PRODUCTS		394,229		388,173		386,510		223,151
GAS TURBINE FUEL COST, $/B		61.59		61.71		61.94		64.20

(1) CALCULATED TO GIVE 30% RETURN ON TOTAL CAPITAL REQUIREMENT.
(2) CALCULATED ON THE BASIS OF VISCOSITY BLENDING VALUE.

TABLE IV-9

UPGRADING OF HIGH-SULFUR PETROLEUM RESIDUAL OIL TO GAS TURBINE FUEL

ECONOMIC EVALUATION-U.S. GULF COAST-1985

CASE		6010		6020		6030		6040	
		HYDROTREATING OF VACUUM BOTTOMS AT MODERATE SEVERITY		HYDROTREATING OF VACUUM BOTTOMS AT INTERMEDIATE SEVERITY		HYDROTREATING OF VACUUM BOTTOMS AT HIGH SEVERITY		DELAYED COKING OF VACUUM BOTTOMS PLUS HYDROTREATING OF COKER DISTILLATE	
GAS TURBINE FUEL, B/CD		25,495		25,341		24,811		9,467	
NITROGEN, WT%		0.35		0.35		0.29		0.09	
VISCOSITY, CS @100F		1,100		1,100		1,100		1.7	
SULFUR, WT%		0.36		0.27		0.19		0.16	
VANADIUM, PPM		49		30		11		-	
GRAVITY, API		22.9		23.0		23.2		37.7	
INVESTMENT, $THOUS (1984)		CAPACITY, UNITS/SD	INVESTMENT	CAPACITY, UNITS/SD	INVESTMENT	CAPACITY, UNITS/SD	INVESTMENT	CAPACITY, UNITS/SD	INVESTMENT
DELAYED COKING UNIT, B CHARGE		-	-	-	-	-	-	13,300	25,410
HYDROTREATING UNIT, B CHARGE		22,350	107,260	22,280	111,520	22,210	118,220	9,420	9,880
PARTIAL OXIDATION H2 PLANT, MSCF H2		18,500	52,360	19,650	54,520	21,230	57,400	-	-
STEAM REFORMING H2 PLANT, MSCF H2				-	-	-		6,640	10,050
H2S RECOVERY UNIT, LT H2S		109	7,730	112	7,800	116	7,890	38	5,310
SULFUR PLANT, LT SULFUR		102	12,800	105	12,960	109	13,150	36	8,350
GAS PLANT, B CHARGE		-	-	-	-	-	-	-	-
SUBTOTAL PROCESS UNITS			180,150		186,800		196,660		59,200
CATALYSTS AND ROYALTIES			17,880		16,640		20,570		1,240
UTILITY FACILITIES			7,070		7,290		7,450		3,560
TANKAGE			8,040		8,020		7,940		4,180
MISCELLANEOUS OFF-SITES FACILITIES			65,020		67,300		70,610		22,290
CONTINGENCY AT 20%			55,630		57,610		60,650		18,090
TOTAL PLANT INVESTMENT			333,790		345,660		363,880		108,560
WORKING CAPITAL			28,270		28,410		28,530		12,660
TOTAL CAPITAL REQUIREMENT			362,060		374,070		392,410		121,220
RETURN FROM CONVENTIONAL PRODUCTS		UNITS/CD	$THOUS/YEAR	UNITS/CD	$THOUS/YEAR	UNITS/CD	$THOUS/YEAR	UNITS/CD	$ THOUS/YEAR
COKE,	$ 40.00/ST	-	-	-	-	-	-	725	10,585
FUEL GAS TO SALES,	$ 56.03/B FOE	-	-	-	-	-	-	281	5,747
SULFUR,	$152.00/LT	92	5,104	95	5,271	98	5,437	32	1,775
AMMONIA,	$312.06/ST	7	797	7	797	9	1,025	-	-
REFINERY FUEL GAS,	$ 56.03/B FOE	356	7,281	376	7,690	400	8,180	692	14,152
REFINERY FUEL OIL,	$ 56.03/B	398	8,139	396	8,099	391	7,996	-	-
REFINERY GAS TO H2 PLANT,	$ 56.03/B FOE	-		-	-		-	235	4,806
VTB TO H2 PLANT,	$ 56.03/B	951	19,449	1,009	20,635	1,090	22,292	-	-
TOTAL RETURN FROM CONVENTIONAL PRODUCTS			40,770		42,492		44,930		37,065
RETURN FROM GAS TURBINE FUEL, $(1)/B		25,495	615,930	25,341	616,469	24,811	615,190	9,467	241,839
TOTAL RETURN FROM PRODUCTS			656,700		658,961		660,120		278,904
COST OF CHARGE									
CEUTA VACUUM BOTTOMS,	$45.44/B (2)	21,509	356,740	21,509	356,740	21,520	356,922	12,500	207,320
NO. 2 FUEL OIL,	$68.65/B	4,130	103,486	3,920	98,224	3,523	88,277	-	-
TOTAL COST OF CHARGE		25,639	460,226	25,429	454,964	25,043	445,199	12,500	207,320
MANUFACTURING EXPENSE									
REFINERY FUEL,	$56.03/B	754	15,420	772	15,788	791	16,177	692	14,152
POWER, PURCHASED,	$ 0.0654/KWH	185,140	4,419	198,970	4,750	202,230	4,827	74,870	1,787
WATER, FRESH,	$ 0.0686/THOUS GAL	1,255	31	1,315	247	1,399	35	414	10
SUBTOTAL UTILITIES			19,870		20,785		21,039		15,949
REFINERY LIQ. TO H2 PLANT,	$56.03/ B	951	19,449	1,009	20,635	1,090	22,292	-	-
REFINERY GAS TO H2 PLANT,	$56.03/ B FOE			-		-	-	235	4,806
CHEMICALS			949		993		1,051		169
CATALYSTS			14,119		14,885		16,810		228
INVESTMENT-BASED ITEMS			28,373		25,382		30,910		9,334
LABOR-BASED ITEMS		336	5,096	336	5,096	336	5,096	312	4,732
TOTAL MANUFACTURING EXPENSE			87,856		91,776		97,198		35,218
TOTAL EXPENSE			548,082		546,740		542,397		242,538
RETURN ON TOTAL CAPITAL AT 30% BEFORE TAXES			108,618		112,221		117,723		36,366
TOTAL EXPENSE PLUS RETURN ON INVESTMENT LESS RETURN FROM CONVENTIONAL PRODUCTS			615,930		616,469		615,190		241,839
GAS TURBINE FUEL COST, $/B			66.17		66.65		67.93		69.99

(1) CALCULATED TO GIVE 30% RETURN ON TOTAL CAPITAL REQUIREMENT.
(2) CALCULATED ON THE BASIS OF VISCOSITY BLENDING VALUE.

APPENDIX C

PLOTS OF UPGRADING COSTS VERSUS GAS TURBINE FUEL IMPURITIES

Figure III-21

UPGRADING OF LOW-SULFUR SOUTH LOUISIANA RESIDUAL FUEL OIL TO GAS TURBINE FUEL

Upgrading Cost vs. Gas Turbine Fuel Vanadium Content

Key: O Base Case - Blend Vacuum Bottoms to No. 6 Fuel Oil

△ Decarbonizing of Vacuum Bottoms

□ Delayed Coking of Vacuum Bottoms Plus Hydrotreating of Coker Distillate: (a) C_5-950°F; (b) 375-950°F; (c) 650-950°F

X Hydrodesulfurization of Vacuum Bottoms

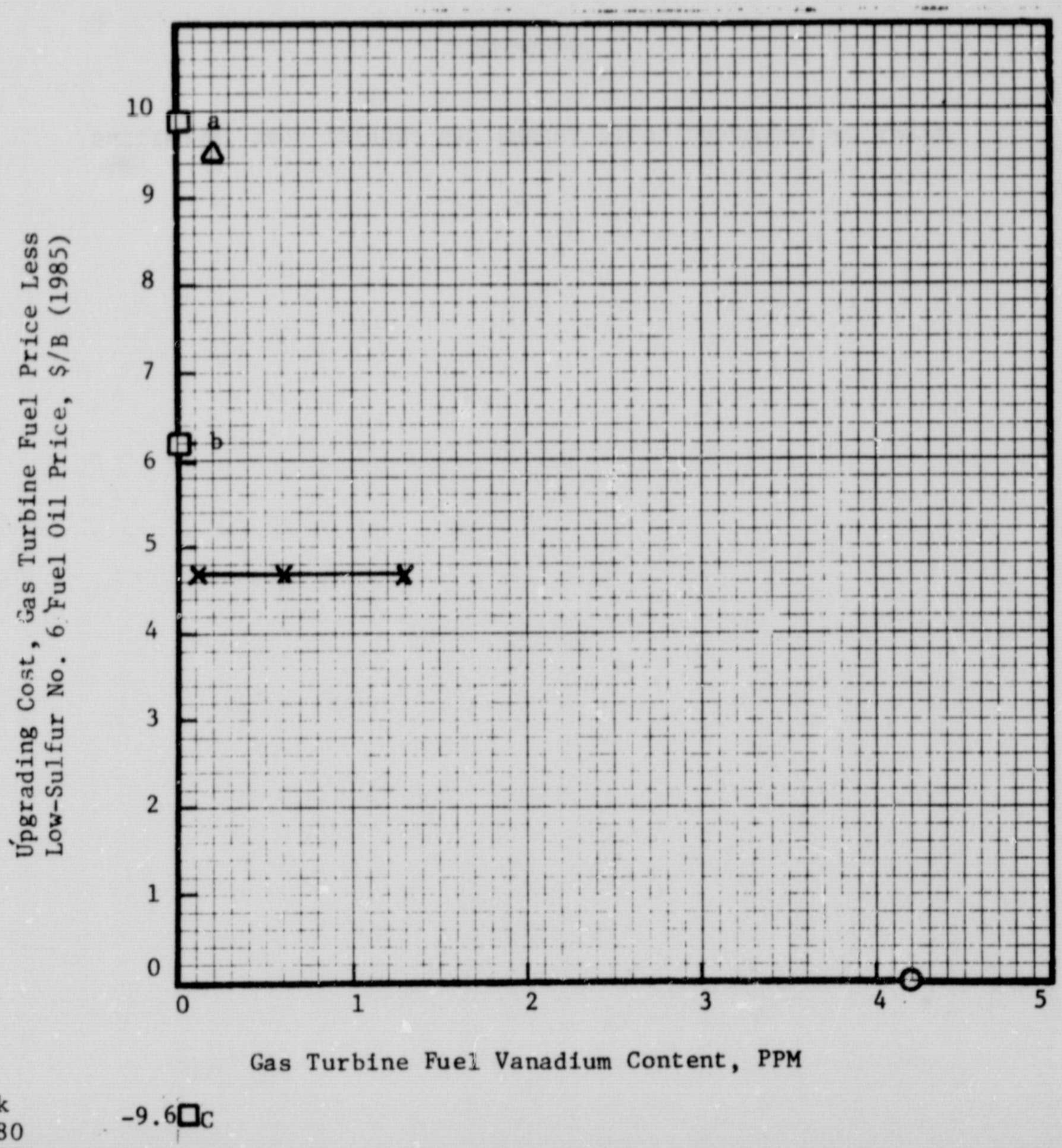

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Figure III-22

UPGRADING OF LOW-SULFUR SOUTH LOUISIANA RESIDUAL FUEL
OIL TO GAS TURBINE FUEL

Upgrading Cost vs. Gas Turbine Fuel Sulfur Content

Key: ○ Base Case - Blend Vacuum Bottoms to No. 6 Fuel Oil

△ Decarbonizing of Vacuum Bottoms

□ Delayed Coking of Vacuum Bottoms Plus Hydrotreating of Coker Distillate: (a) C_5-950°F: (b) 375-950°F: (c) 650-950°F

× Hydrodesulfurization of Vacuum Bottoms

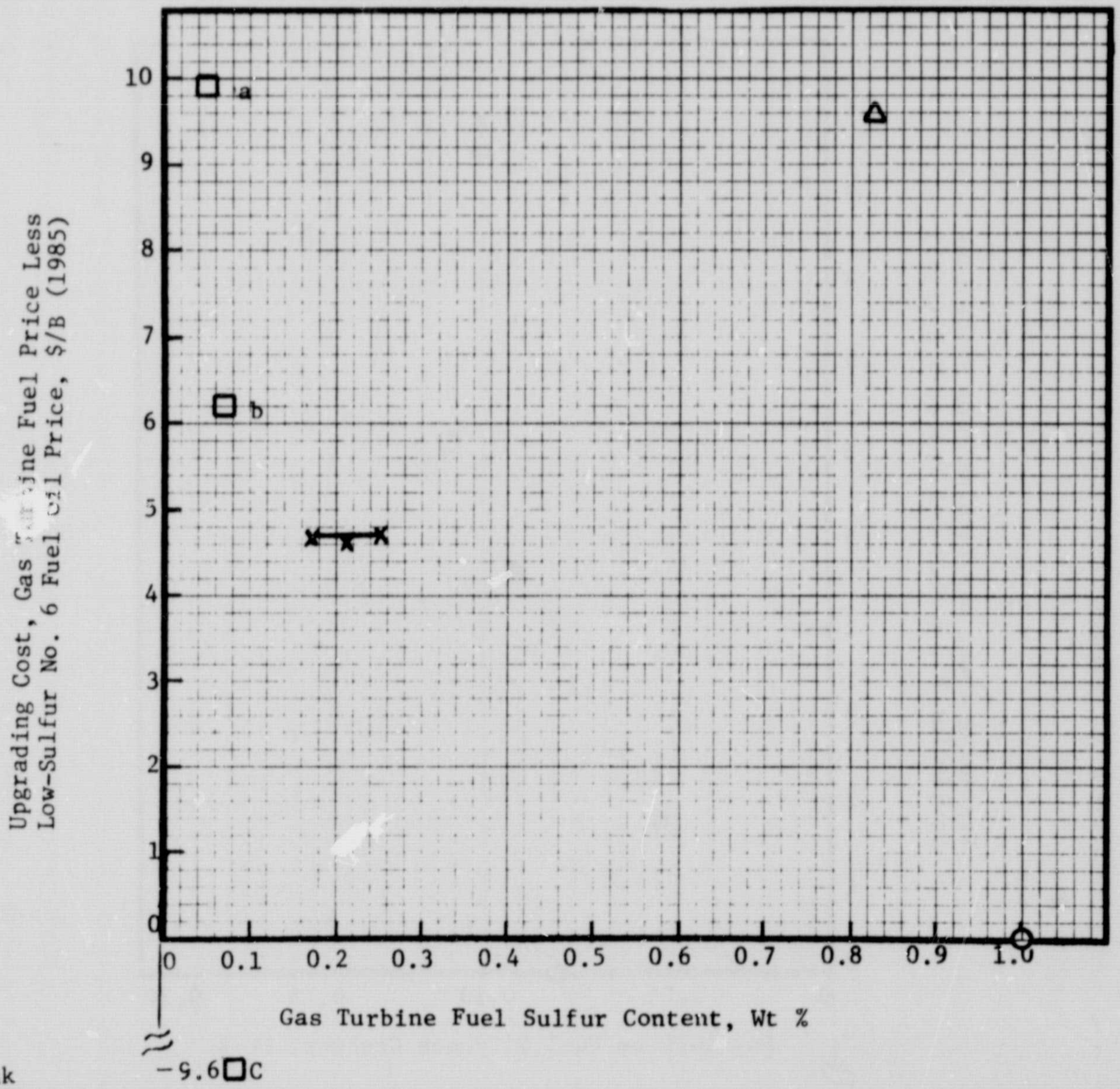

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Figure III-23

UPGRADING OF LOW-SULFUR SOUTH LOUISIANA RESIDUAL FUEL OIL TO GAS TURBINE FUEL

Upgrading Cost vs. Gas Turbine Fuel Nitrogen Content

Key: O Base Case - Blend Vacuum Bottoms to No. 6 Fuel Oil

△ Decarbonizing of Vacuum Bottoms

□ Delayed Coking of Vacuum Bottoms Plus Hydrotreating of Coker Distillate: (a) C_5-950°F; (b) 375-950°F; (c) 650-950°F

✕ Hydrodesulfurization of Vacuum Bottoms

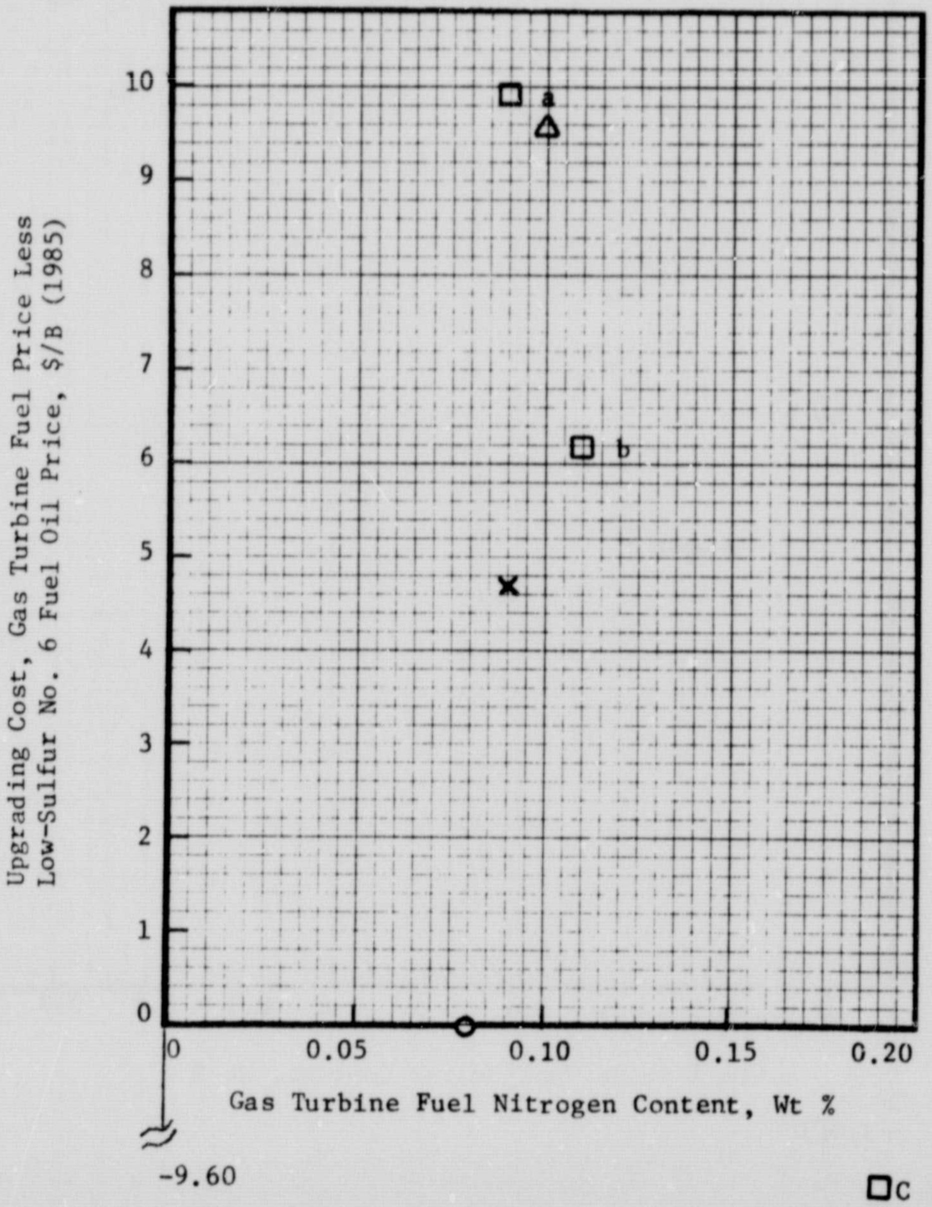

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Figure III-24

UPGRADING OF HIGH-SULFUR CEUTA (VENEZUELAN) RESIDUAL FUEL OIL TO GAS TURBINE FUEL

Upgrading Cost vs. Gas Turbine Fuel Vanadium Content

Key: O Base Case - Blend Vacuum Bottoms to No. 6 Fuel Oil

△ Decarbonizing of Vacuum Bottoms

□ Delayed Coking of Vacuum Bottoms Plus Hydrotreating of Coker Distillate: (a) C_5-950°F; (b) 375-950°F; (c) 650-950°F

× Hydrodesulfurization of Vacuum Bottoms

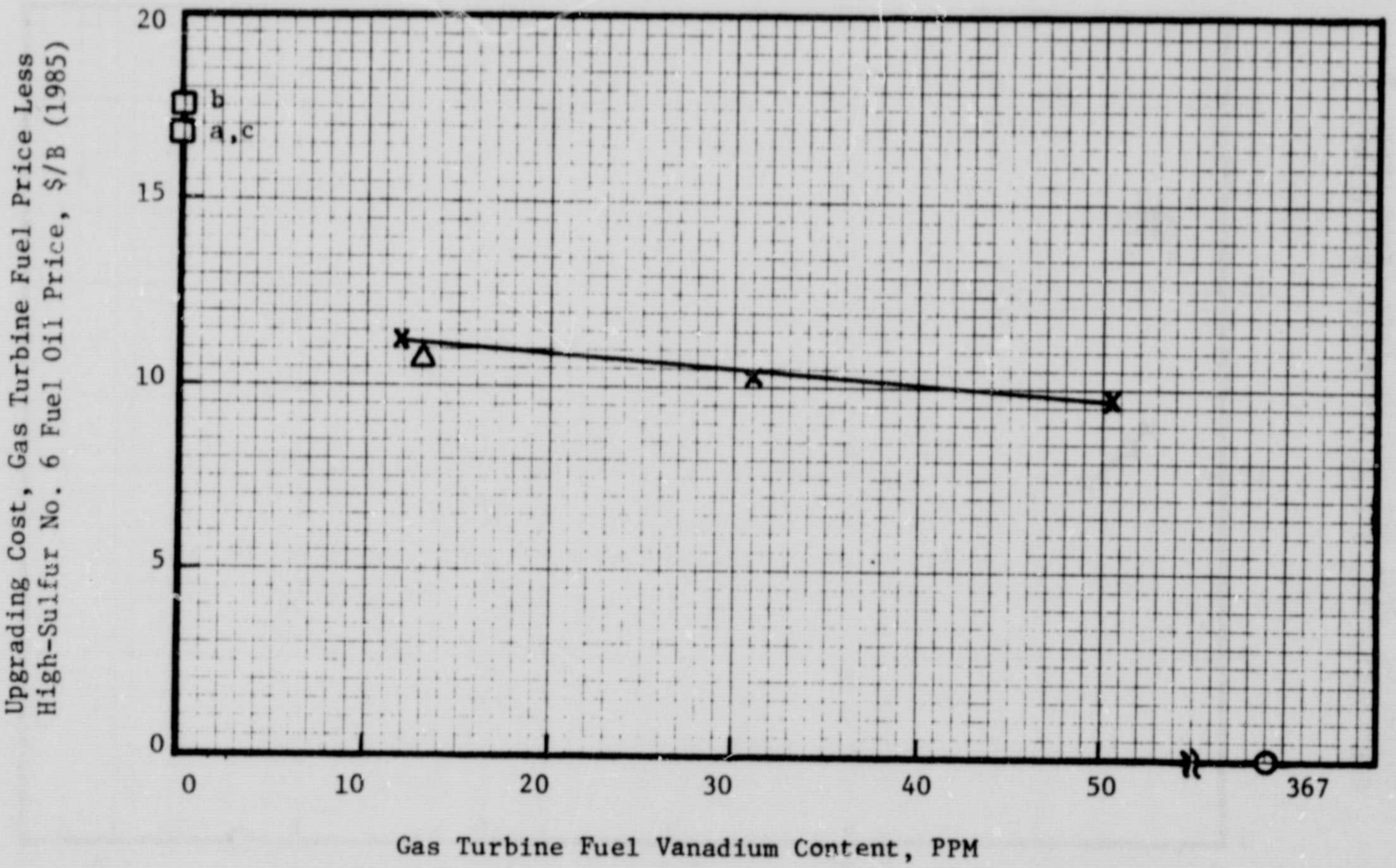

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Figure III-25

UPGRADING OF HIGH-SULFUR CEUTA (VENEZUELAN) RESIDUAL FUEL OIL TO GAS TURBINE FUEL

Upgrading Cost vs. Gas Turbine Fuel Sulfur Content

Key: O Base Case - Blend Vacuum Bottoms to No. 6 Fuel Oil

△ Decarbonizing of Vacuum Bottoms

□ Delayed Coking of Vacuum Bottoms Plus Hydrotreating of Coker Distillate: (a) C_5-950°F: (b) 375-950°F; (c) 650-950°F

× Hydrodesulfurization of Vacuum Bottoms

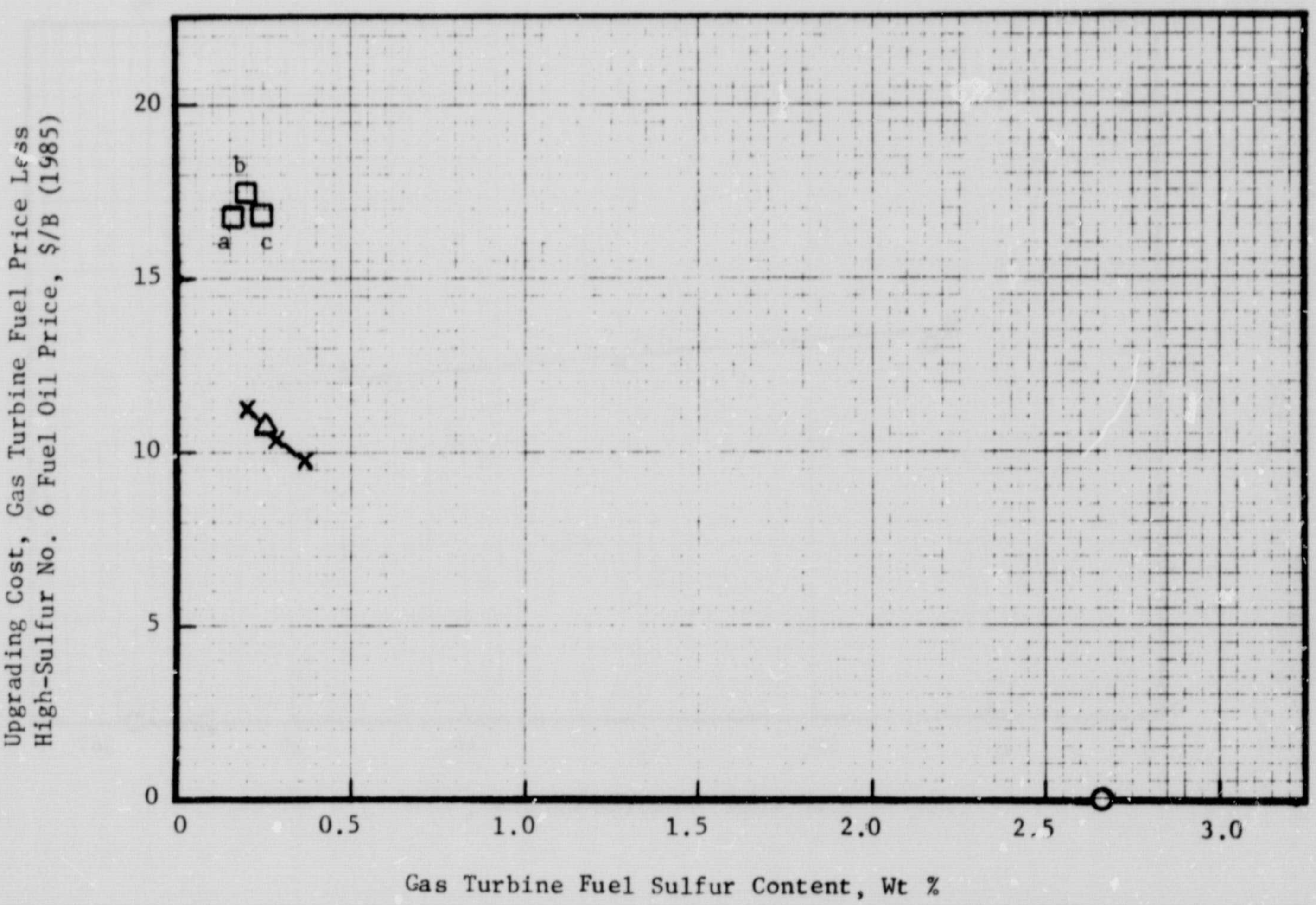

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Figure III-26

UPGRADING OF HIGH-SULFUR CEUTA (VENEZUELAN) RESIDUAL FUEL OIL TO GAS TURBINE FUEL

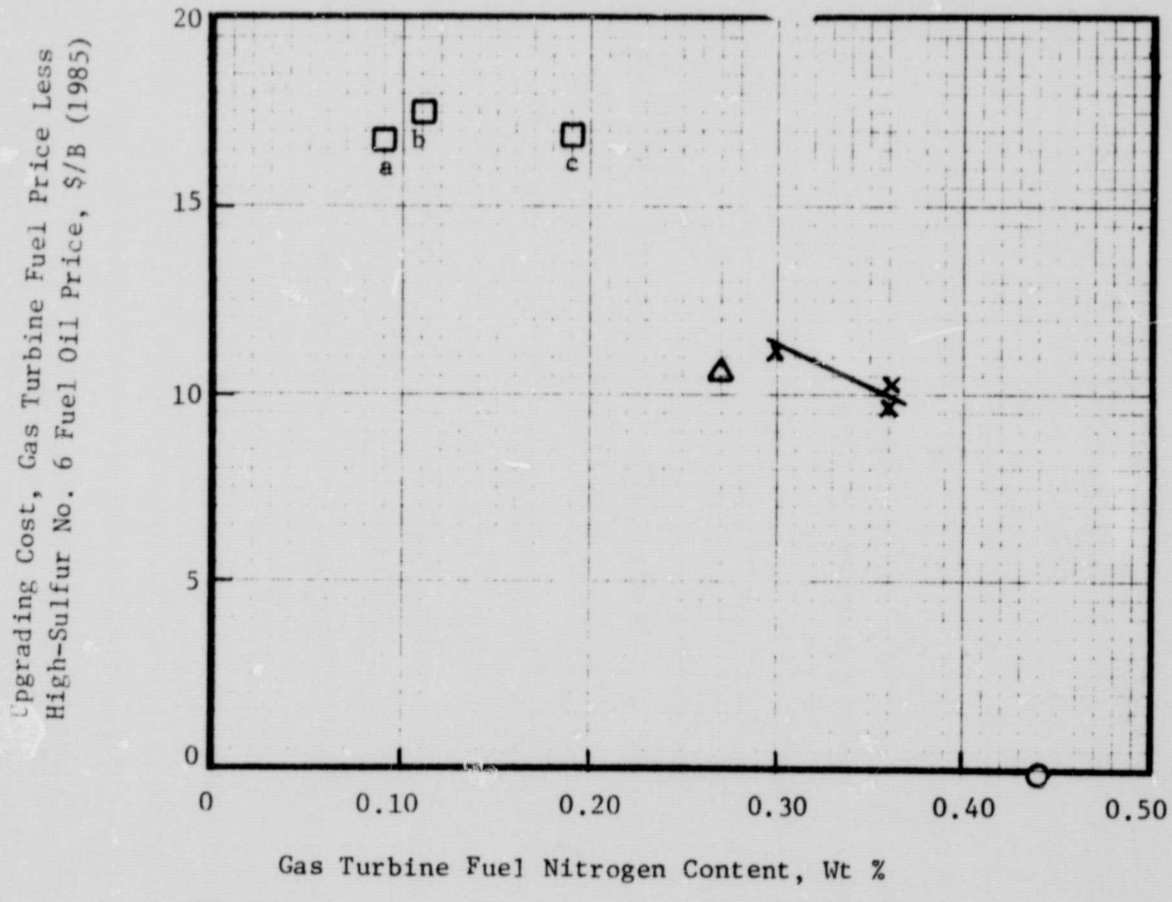
Upgrading Cost vs. Gas Turbine Fuel Nitrogen Content

Key: O Base Case - Blend Vacuum Bottoms to No. 6 Fuel Oil

△ Decarbonizing of Vacuum Bottoms

□ Delayed Coking of Vacuum Bottoms Plus Hydrotreating of Coker Distillate: (a) C_5-950°F; (b) 375-950°F; (c) 650-950°F

× Hydrodesulfurization of Vacuum Bottoms



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